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-10) ________

PREPARED DIRECT TESTIMONY
OF JAMES R. MAGILL
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 TESTIMONY

OF

JAMES R. MAGILL

CHAPTER 10

I. INTRODUCTION

The purpose of my testimony is to present rate design details in support of SDG&E's Dynamic Pricing proposals with the implementation of SDG&E's Advanced Metering Infrastructure (AMI). As described in Chapter 9, the testimony of SDG&E witness Ed Fong, SDG&E committed during the AMI proceeding, A.05-03-015, to include in SDG&E's GRC Phase 2 filing dynamic pricing proposals that were consistent with the illustrative rates presented in the AMI filing.[1] Consistent with Table EF 9-1, my testimony addresses the following rate design proposals:

- Critical Peak Pricing (CPP) Rate Design for >20 kW Customers (Section II);
- TOU Rate Design for < 20 kW Customers (Section III);
- Residential Peak Time Rebate (PTR) (Section IV); and
- CPP and PTR Cost Recovery (Section V).

In addition, my testimony supports studies which evaluate (1) the appropriate seasonality and time periods for the commercial and industrial customer class time-of-use (TOU) rates (Section VI); and (2) the current residential customer baseline allowances (Section VII).

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[1] The illustrative rates were presented in Witness Robert Hansen's Prepared Supplemental, Consolidating, Superseding and Replacement Testimony filed July 14, 2006 in A.05-03-015.

II. DEFAULT CPP RATE DESIGN FOR GREATER THAN 20KW CUSTOMERS

A. Default CPP Rate Design Applicability

In the testimony of SDG&E Witness Hansen in A.05-03-015, illustrative rates were presented for two customer classes: (1) customers with demands greater than 200 kW and (2) customers with demands between 20 and 200 kW. This split between commercial and industrial customers was predicated on previous CPP rate filings where CPP rates were developed for only the greater than 200 kW customer class due to metering limitations.[2] With the implementation of AMI, all customers with demands greater than 20 kW will have the appropriate advanced metering necessary to implement CPP rates.[3] Therefore, SDG&E has designed the proposed CPP rate based on the total greater than 20 kW customer class, rather than bifurcating the class since the metering limitations are no longer relevant.[4] In addition to the current AL-TOU, AY-TOU, A6-TOU and PA-T-1 customer classes, SDG&E would also include customers currently on Schedules A-TOU, AD and PA that would qualify for Schedule AL-TOU.[5] The characteristics of the proposed CPP rate include a Capacity Reservation charge (CRC), a CPP energy rate applicable to load in excess of the CRC demand level, and lower on-

[2] Currently only customers with demands greater than 200 kW have the appropriate interval metering that is required to implement CPP pricing options.

[3] As explained in SDG&E Witness Fong's July 14, 2006 AMI testimony, SDG&E's C&I customers will be converted to new AMI solid-state interval meters with AMI communications.

[4] In the event the Commission denies SDG&E's AMI application, SDG&E will need to file supplemental testimony to address the CPP rate for only greater than 200 kW customers.

[5] Customers with demands that exceed 20 kW for twelve (12) consecutive months qualify for Schedule AL-TOU. Schedule A-TOU is currently closed but is applicable to customers with demands less than 40 kW. Schedule AD is closed but is applicable to customers with demands between 20kW and 500kW. Schedule PA incorporates agricultural customers with demands that can exceed 20 kW.

peak, semi-peak and off-peak prices. Each of these components is discussed in more detail below.

B. Default CPP Rate Design

In developing the proposed CPP rate, SDG&E has designed the rate to be revenue neutral with rates including the GRC Phase 1 proposed revenue requirement.[6] The billing determinants used to design the proposed CPP energy rate were developed based on the combined AL-TOU, AY-TOU, A6-TOU and PA-T-1 customer classes and 2005 load research data for the summer period May 2005 through September 2005. 2005 summer on-peak energy usage (11am – 6pm) for the highest nine (9) days was used to split 2008 forecast on-peak energy sales into CPP and on-peak energy billing determinants for each of the service voltage levels. In addition, 2005 load information was used to determine the average hourly load during the top nine (9) summer days for the greater than 20 kW customer class.[7] The applicable CPP rate is based on the marginal capacity cost multiplied by the average load associated with the greater than 20 kW customer class during the top nine (9) CPP days plus the summer on-peak marginal energy cost.[8]

As described in Chapter 12, the testimony of Steve Jack, the proposed CPP trigger conditions are established based on the top thirteen (13) days reflecting the top 91 hours. While designing the CPP rate based on fewer days than expected under the proposed triggers may appear disjointed, as discussed by SDG&E Witness Joe Velasquez (Chapter

[6] Rates will need to be updated to reflect revenue requirement changes that occur prior to implementation.
[7] As presented in Chapter 12, the testimony of Steve Jack, the proposed maximum number of CPP days is eighteen (18).
[8] SDG&E has used a marginal capacity cost of $76.40/kw-yr as proposed in Chapter 4, the Prepared Testimony of SDG&E witness James Parsons.

11), SDG&E is proposing "soft" triggers for the default CPP rate. This proposal is consistent with SDG&E's filing in response to the Assigned Commissioner Ruling Requiring Utility Proposals to Augment 2007 Demand Response Programs issued August 9, 2006. In that filing, SDG&E recommended changing the CPP trigger mechanism such that program events **MAY** be called (as compared to the existing language that specified that events **WILL** be called). By softening the trigger language, SDG&E believes that it could better manage the CPP program by calling the program events only when necessary.[9] In D.06-11-049, the Commission adopted SDG&E's recommendation.[10] Thus, it is SDG&E's desire to preserve the opportunity to only trigger program events when all conditions warrant, not simply mechanically based on the achievement of a certain set of predetermined conditions.[11]

Given that SDG&E has proposed "soft" triggers, it would be inappropriate to design the proposed CPP rate based on thirteen (13) CPP days when there is a high probability that less than thirteen (13) days will actually be called.[12] Designing the proposed CPP rate on thirteen (13) days under these conditions would build in an inherent revenue under collection that would provide unintended cost savings to customers. The intent of the CPP rate is to provide customer savings based on demand reductions provided during the highest system demand days to establish demand response as a future capacity resource and not a windfall benefit for just being on the rate. Thus in developing the proposed CPP rate, SDG&E has tried to balance the input received from

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[9] SDG&E's response to the Assigned Commissioner Ruling Requiring Utility Proposals to Augment 2007 Demand Response Programs filed August 31, 2006, p.2.
[10] D.06-11-049, p.61.
[11] The proposed trigger conditions are described in the testimony of SDG&E witness Steve Jack, Chapter 12.
[12] During the period 2003 – 2006, SDG&E has only called 4, 6, 5 and 10 CPP days respectively.

customers that CPP events only be called when needed, with the overall intent of the CPP rate.[13]

C. Capacity Reservation Charge

Consistent with SDG&E's illustrative rates presented in A.05-03-015, SDG&E is proposing to offer an optional Capacity Reservation Charge (CRC) under the default CPP tariff.[14] As explained in Chapter 11, the testimony of Joe Velasquez, the CRC component will allow customers to manage their bill fluctuation by paying for load that cannot be reduced during CPP events by means of a predictable monthly demand charge. For 2008, customers with interval meters in place in 2007 may select a kW threshold based on their maximum on-peak demand during the top nine (9) system load days in 2007, on which they will be billed a flat rate per kW per month. Customers without an interval meter during the summer of 2007 may select a kW threshold based on their maximum on-peak demand during the summer of 2007, on which they will be billed a flat rate per kW per month. In subsequent years, as AMI meters are installed, all customers would select a kW threshold based on their maximum demand during the prior year's CPP periods.[15] Consumption associated with this demand level will not be subject to the CPP period energy prices, but instead paid for in a levelized CRC charge throughout the year. When a CPP event is called, customers pay the CPP energy rate for only usage above their reserved levels. The otherwise applicable on-peak energy rate will apply to reserved usage.

[13] As discussed in Chapter 9, the testimony of Ed Fong, SDG&E recognizes that due to some customers' load shapes there will be a group of "structurally advantaged" customers that will realize cost savings on the CPP rate absent any demand reductions. However, it is not SDG&E's intent to provide all customers on the CPP rate with similar windfall benefits.

[14] The proposed CRC is based on a generation marginal capacity cost of $76.40 per kW per year.

[15] In the event that a customer does not select a kW threshold amount, the customer will be assigned a default value based on fifty (50) percent of their applicable maximum demand.

D. Energy Rates

1. CPP Energy Rate

The CPP energy rate is calculated to ensure recovery of the CPP marginal capacity cost revenues during CPP event hours, in addition to the on-peak marginal energy cost.[16] The CPP energy rate equals the CPP marginal capacity cost revenues, minus the capacity revenues associated with the CRC, divided by forecasted billed CPP usage, plus the summer on-peak marginal energy rate.[17]

2. On-peak, semi-peak and off-peak rates

The proposed on-peak and semi-peak rates are based on the proposed AL-TOU commodity rates adjusted to maintain revenue neutrality. The off-peak rates are set based on the AL-TOU customer class' marginal energy costs as the adjustment required to maintain revenue neutrality resulted in energy rates that were below marginal cost. As a result, the adjustment required for revenue neutrality is applied to only the on-peak and semi-peak energy rates. The same adjustment is applied to each energy rate to maintain the appropriate rate differentials. The proposed default CPP rate is presented in Attachment JRM 10-1.

E. Bill Impacts

SDG&E has conducted bill impact scenarios for a sample of customers with demands greater than 20 kW to estimate the number of customers that could potentially see adverse bill impacts under the proposed default CPP rate. In running the bill impacts, SDG&E compared customers' bills under the proposed CPP tariff, assuming nine (9)

[16] The CPP event hours are 11am – 6 pm as discussed in Chapter 12, the testimony of Steve Jack.
[17] The CPP billing determinants and CRC revenues reflect the proposed fifty (50) percent default CRC.

CPP days and a fifty (50) percent CRC, to the customers' proposed applicable rate.[18] In determining the nine (9) CPP days, SDG&E identified the highest peak load days during the summer of 2006. Based on this analysis, it is estimated that customer annual bill impacts can range from a decrease of 22.5 percent to an increase of 30 percent, with approximately 88 percent of the customers falling within plus or minus five (5) percent. It should be noted that the bill impacts do not reflect any potential CPP-period load reductions that customers may be able to achieve, which will have a downward affect on customers' actual bills. A frequency distribution of the potential customer bill impacts is provided in Attachment JRM 10-2.

F. Optional CPP rates

Currently there are two existing optional CPP rates, Voluntary CPP and CPP-E, which SDG&E seeks to update to reflect the proposed GRC Phase 1 revenue requirement and rate design principles outlined by SDG&E witness Hansen.

1. Voluntary CPP

The voluntary CPP rate (EECC-CPP) schedule is available to customers currently served under a TOU schedule receiving bundled utility service with an annual maximum demand 20 kW or greater.[19] The rate design consists of two CPP periods, Period 1 effective 3pm – 6pm and Period 2, effective 11am – 3pm. The rates for Period 1 and Period 2 are based on multiples of the current on-peak and semi-peak rates. Period 1 is equal to ten (10) times the on-peak rate and Period 2 is equal to five (5) times the semi-peak rate.

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[18] The customer CPP bill analysis reflects first-year bill impacts excluding bill protection.

[19] As discussed in the testimony of Joe Velasquez, Chapter 11 p. JV-11, customers currently on the voluntary rate will be required to complete their twelve month commitment before transitioning to the default CPP tariff.

The billing determinants used to design the proposed voluntary CPP energy rates were based on the combined AL-TOU, AY-TOU, A6-TOU and PA-T-1 customer classes and 2005 load research data for the summer period May 2005 through September 2005. 2005 summer on-peak energy usage (11am – 6pm) for the highest nine (9) days was used to split 2008 forecast on-peak energy sales into CPP Period 1, Period 2 and on-peak energy billing determinants for each of the service voltage levels. When the rate multiples are applied to the proposed summer on-peak and semi-peak energy rates, the proposed voluntary CPP rates result in a revenue under collection. The adjustment required to maintain revenue neutrality is applied to the Period 1 and Period 2 rates to ensure that the proposed non-CPP on-peak, semi-peak and off-peak energy rates do not exceed the energy rates of the otherwise applicable rate. The intent of the CPP rate is to send customers a price signal to encourage them to curtail during the highest summer demand days. In order for this incentive to be retained, the CPP energy rates cannot exceed the otherwise applicable rate for all non-CPP hours. The proposed voluntary CPP rate is presented in Attachment JRM 10-3

2. CPP-E

The CPP-E rate is an optional rate currently available to customers with demands 300 kW or greater currently receiving bundled utility service who currently have an Interval Data Recorder (IDR) meter installed with related telecommunications compatible with the utility's meter reading and telecommunication system.[20] This rate is designed for customers that are able to reduce load in emergency situations, as defined by SDG&E Grid Operations personnel, and therefore to provide immediate load reduction when it is

[20] As discussed in the testimony of Joe Velasquez, Chapter 11, SDG&E proposes to expand the applicability of the CPP-E tariff.

determined that there is a lack of available local resources. Participating customers are required to curtail load within 15 to 30 minutes of electronic notification. This rate is designed to be called for a minimum of five (5) annual "alert period" program hours up to a maximum of 80 annual "alert period" program hours and will be available to customers for a 12-month period.[21]

The billing determinants used to design the proposed CPP-E rate were based on the combined AL-TOU, AY-TOU, A6-TOU and PA-T-1 customer classes and 2005 load research data. 2005 energy usage for the top forty (40) hours was used to split 2008 forecast energy sales into CPP-E and on-peak, semi-peak and off-peak energy billing determinants for each of the service voltage levels. In addition, 2005 load information was used to determine the average hourly load during the top forty (40) hours for the greater than 20 kW customer class. The energy charge for all usage during the CPP-E Alert Period is calculated to ensure recovery of the CPP-E marginal capacity cost revenues during CPP event hours, in addition to the on-peak marginal energy cost. The CPP-E energy rate equals the CPP-E marginal capacity cost revenues, divided by forecasted billed CPP-E usage, plus the summer on-peak marginal energy rate. The proposed on-peak, semi-peak and off-peak rates are set based on the AL-TOU customer class' marginal energy costs as the adjustment required to maintain revenue neutrality resulted in energy rates that were below marginal cost. As a result, the adjustment required for revenue neutrality is applied to the CPP-E energy rates. The same adjustment is applied to each CPP-E rate to maintain the appropriate rate differentials. The proposed CPP-E rate is presented in Attachment JRM 10-4.

[21] The CCP-E rate schedule can be called anytime during the year and is not limited to only the summer months.

G. Opt-out rates

Customers will have the ability to opt out of the default CPP tariff to their otherwise applicable tariff which can also include other available optional demand response and interruptible programs as explained by SDG&E witness Velasquez.[22] The opt-out commodity rates will be those that are ultimately adopted in the GRC Phase 2 proceeding, adjusted for any commodity rate changes that may take place between January 31, 2007 and the effective date of the default CPP rates.

III. TIME-OF-USE (TOU) RATE PROPOSAL FOR LESS THAN 20 KW CUSTOMERS

A. AS-TOU Rate Design

As discussed in Chapter 9 (SDG&E Witness Fong) with the implementation of AMI SDG&E recommends that all current customers with demands less than 20 kW (primarily customers on Schedule A) convert to a three (3) period TOU rate with summer / winter components.[23] As discussed by Witness Fong, SDG&E proposes that Schedule A be phased out and existing and new customers be converted to the new proposed Schedule AS-TOU on the next billing period following ninety (90) days after the appropriate metering is installed with the implementation of AMI.[24]

In designing the proposed AS-TOU rate for customers with demands less than 20 kW, SDG&E proposes a demand charge based rate structure similar to current Schedule AL-TOU. To develop the energy rates, billing determinants for non-TOU customers

[22] Customers will be eligible to opt-out of the default CPP rate upon completion of the twelve (12) month bill protection period as discussed in Chapter 11.
[23] SDG&E proposes to use the same seasonal and time period definitions currently applicable to Schedule A-TOU.
[24] As explained by SDG&E Velasquez (Chapter 11), these customers will be eligible for a peak-time rebate (PTR) during CPP days.

were calculated by applying allocation factors based on ten-year historical load research information to the 2008 sales forecast for Schedule A customers. These determinants were then aggregated with existing Schedule A-TOU customers. Demand billing determinants for Schedule A customers were developed using 2005 load research information.

Demand and energy rates were derived only for the distribution and commodity rate components. To mitigate the bill impacts for Schedule A customers, the demand charges were established at 1 percent of the currently proposed AL-TOU distribution and commodity demand charges. The distribution and commodity TOU energy rates were calculated using the currently proposed Schedule A energy rates as on-peak rates. The semi-peak and off-peak rates were then derived by applying the AL-TOU semi-peak and off-peak marginal energy cost differentials to the on-peak and semi-peak rates respectively. The on-peak, semi-peak and off-peak rates were then adjusted to maintain revenue neutrality with the distribution and commodity rates proposed for the combined Schedule A and A-TOU customer class. The same adjustment was applied to each energy rate to maintain the rate differentials. The proposed AS-TOU rate is presented in Attachment JRM 10-5.

B. Bill Impacts

SDG&E has conducted bill impact scenarios for a sample of customers less than 20 kW to estimate the number of customers that could potentially see adverse bill impacts under the proposed AS-TOU rate. In running the bill impacts, SDG&E compared customers' bills under the proposed AS-TOU tariff to the customers' proposed applicable rate.[25] The results of the sample bill impacts were then expanded to incorporate the total population. Based on this analysis, it is estimated that customer bill impacts can range from a decrease of 12.5 percent to an increase of 7.5 percent, with approximately 75 percent of the customers falling within plus or minus 2.5 percent. It should be noted that the bill impacts do not reflect any potential PTR credits that customers may be able to achieve, which will have a downward affect on customer's actual bills. A frequency distribution of the potential customer bill impacts is provided in Attachment JRM 10-6.

IV. RESIDENTIAL PEAK-TIME REBATE (PTR)

In A.05-03-015, SDG&E Witness Mark Gaines in Chapter 5 describes SDG&E's specific PTR proposal including an illustrative PTR credit. Provided in Attachment JRM 10-7 is a cost-based credit calculation based on 2005 load research demand and energy data for the residential class supporting the proposed PTR credit outlined in the testimonies of SDG&E Witnesses Fong (Chapter 9) and Willoughby (Chapter 13). The cost-based PTR credit was derived by dividing the average hourly residential class demand during the top nine (9) days by energy usage associated with the top nine (9) days.

V. DEFAULT CPP AND PTR COST RECOVERY

With the implementation of the default CPP rate, over collections or under collections of commodity revenue can occur when the number of CPP days called differs from the number days assumed in designing the proposed default CPP tariff. To the extent any over collections or under collections occur as a result of SDG&E calling more or less CPP days than used in the design of the default CPP rate, SDG&E proposes that

[25] Proposed Schedule AS-TOU is applicable to customers upon implementation of the AMI meters, which is expected to begin mid 2008.

these revenue changes be tracked separately within the greater than 20 kW customer class and recovered within the greater than 20kW class through SDG&E's Energy Resource Recovery Account (ERRA). In addition, SDG&E proposes to track and recover within the residential and small commercial customer classes (through the ERRA account) the revenues associated with SDG&E's proposed PTR credits. By tracking and recovering these revenues within each class SDG&E intends to mitigate any cross subsidization among the customer classes as a result of the implementation of AMI rate designs.

VI. TIME-OF-USE SEASONALITY STUDY

SDG&E has conducted an analysis of its seasonal periods for its commercial loads to determine whether the month of October should be included in its summer season definition. In addition, SDG&E reviewed the applicability of the winter on-peak period (5pm – 8pm) for the commercial and industrial class.

Currently, SDG&E defines its residential summer season to include May through October, but for commercial and industrial customers, the summer season is defined as May through September. In determining whether the month of October should be included in the summer season, a variety of different analyses was performed for the commercial class. In analyzing the month of October, peak system loads were identified and compared to other summer months, and the ranking of October peaks was reviewed. The time of day in which system peaks occurred during all months were also reviewed as well as the commercial class peak time during all months of the year. Finally, a population weighted twenty year average cooling degree day analysis was developed for each summer month. In analyzing the winter on-peak period applicability, the system peaks during summer and winter were examined over a five year period as well as the time-period in which the class peak occurred.

Based on the results of the analyses conducted, SDG&E recommends that its current commercial customer summer definition of May- September be expanded to include October and the winter on-peak period be eliminated for the commercial and industrial class. However, SDG&E proposes not to implement these recommendations at this time. To implement this recommendation now would be extremely costly as it would require SDG&E to reprogram over 20,000 TOU meters. Since existing TOU meters are not equipped with the capability of being reprogrammed remotely, thousands of field visits would be required in order for them to be reprogrammed. A reprogramming effort of this magnitude could not be accomplished at a single point in time for the thousands of TOU meters. The existing TOU months and time periods need to remain as they are currently defined until such time as all TOU meters have been replaced with AMI interval data meters. Therefore, SDG&E proposes to make the transition from a 5 month summer period to a 6 month summer period and eliminate the winter on-peak period following the deployment of its Advanced Metering Infrastructure (AMI). In order to maintain a fair and consistent rate structure SDG&E will need to make this seasonal definition change during the beginning of the next year after all AMI meters are installed. All meters are projected to be installed by year-end 2010, therefore SDG&E anticipates that the seasonal and time period changes will take effect on January 1st 2011. The season and time period analysis is provided in Attachment JRM 10-8.

VII. RESIDENTIAL BASELINE ANALYSIS

A. Current Baseline Allowances

As discussed by SDG&E Witness Hansen in Chapter 2, SDG&E has reviewed the current baseline allowances for each of the different climate zones and customer types. In conducting the baseline allowance analysis, SDG&E compared the average residential usage based on the most recent four (4) year historical period (2002-2005) to current baseline values.[26] The present baseline quantities have closely matched the target usage since the implementation of D.02-04-026, which addressed baseline allowances in the context of AB1X.[27] Based on customer usage data from 2002 through 2005, present baseline quantities have consistently encompassed usage near the top of the range specified or, in some instances, beyond the top of the range. Of the sixteen different baseline allowances in the SDG&E tariffs, ten (10) fell within the upper end of the range, and six (6) exceeded the top of the range. Baseline consumption for individual climate zones and service types deviated from target percentages by less than 3% for nearly all customers, with the primary exception of the coastal all-electric customers whose baseline exceeded the target amount by 11% to 12% because of the "up not down" rule.[28] Furthermore, the present baseline quantities encompassed, on average, 99% of the target residential annual electric consumption during the four-year period. The baseline allowance analysis is provided in Attachment JRM 10-9.

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[26] Values for the four (4) year historical period were developed using the bill frequency method adopted by the Commission in D.83-12-065.

[27] In D.02-04-026, the baseline allowances were set at the maximum of the allowed Statutory range. Public Utilities Code § 739(d)(1) requires that baseline quantities be based on average residential usage, and set in a range of 50% to 60% of use, except for residential gas customers and all-electric customers, for whom the baseline is set in a range of 60% to 70% during the winter season.

[28] Ordering Paragraph 10 of D.02-04-026 specifies that electric utilities taking power from the Department of Water Resources may increase but not decrease baseline quantities.

B. Seasonal Residences

In Ordering Paragraph (OP) 10 of D.04-02-057 on Phase 2 issues related to baseline allowances, the Commission adopted the policy that seasonal residences should be excluded from baseline calculations in climate zones if their inclusion would decrease baseline quantities by a 3% materiality threshold.

In accordance with D.04-02-057, SDG&E used the Commission-approved "PG&E proxy" method for excluding the usage of seasonal residences from baseline allowance calculations. The proxy method excludes the set of lowest bills equivalent to the percentage of seasonal residences, as determined from the 2003 Residential Appliance Saturation Study. These percentages, shown in Attachment JRM 10-10, were used as proxies to exclude a corresponding portion of usage from the bill frequency calculations that determine the baseline allowance quantities. For example, in the Mountain climate zone, 10.7% of basic electric customers were estimated to be seasonal customers; therefore, according to the proxy method, 10.7% of the bills with the lowest monthly consumption amounts were excluded from the bill frequency analysis.

Based upon SDG&E's analysis, the results indicate that there are no instances in which the inclusion of seasonal residences would decrease the baseline quantity by an amount sufficient to meet the 3% materiality threshold. Therefore, SDG&E does not need to revise the allowances for the summer or winter seasons in any of its climate zones due to the presence of seasonal residences. The baseline allowance quantities by season with seasonal residences excluded and included are present in Attachment JRM 10-11.

C. Baseline Allowance Exclusions for Seasonal Residences

In Ordering Paragraph (OP) 13 of D.04-02-057 on Phase 2 issues on baseline allowances, the Commission required each electric utility to submit in its GRC an assessment of whether it should deny baseline quantities to seasonal residences.[29] In response to this requirement, SDG&E has conducted a threshold analysis, which determined that seasonal residences had no material affect on any of the baseline allowances. The results of the study show that only the baseline for the mountain climate zone was remotely impacted by seasonal residences (less than 3%). The mountain climate zone contains approximately 13,400 customers, which is approximately 1.1% of the total residential population. Based on the results of the analysis, SDG&E does not believe that the development of baseline allowance exclusions for seasonal residences would provide any material bill savings to the remaining permanent resident customers within the mountain climate zone. In addition, given the minimal impact, it is very unlikely that the benefits to the remaining residential class would exceed the costs of identifying and administering a program of baseline allowance exclusions for seasonal residences. The results of the analysis are presented in Attachment JRM 10-11.

This concludes my prepared testimony.

[29] The assessment is required to include the proportion of seasonal residences in each climate zone, the effect a baseline exclusion would have on the permanent residents' bills and costs (actual or projected) of administering an equitable program.

VIII. WITNESS QUALIFICATIONS

My name is James R. Magill. My business address is 8306 Century Park Court, San Diego, California 92123-1593. I am employed by San Diego Gas and Electric (SDG&E) as the Manager – Electric Forecasting and Analysis. In this position I am responsible for analytical functions such as, electric demand and energy forecasting, load research data and energy usage analysis. I joined SDG&E in December 1993 and have held various positions within SDG&E in the areas of Regulatory Affairs and Customer Service. I assumed my current position in March 2004. Prior to joining SDG&E, I was employed by Duke Power Company and Potomac Electric Power Company.

I received a Bachelor of Arts degree in Economics from Bucknell University in 1983. I received a Masters of Business Administration degree from the University of North Carolina at Charlotte in 1988, where my areas of concentration included economics and finance.

ATTACHMENT

JRM 10-1

Attachment JRM 10-1.1
SAN DIEGO GAS & ELECTRIC COMPANY
DEFAULT CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule AL-TOU	(B) Proposed Default CPP Rates	Line #
1	Capacity Reservation Charge ($ per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Demand: Summer			9
10	Secondary	5.64		10
11	Primary	5.56		11
12	Secondary Substation	5.64		12
13	Primary Substation	5.56		13
14	Transmission	5.43		14
15	Demand: Winter			15
16	Secondary	0.18		16
17	Primary	0.18		17
18	Secondary Substation	0.18		18
19	Primary Substation	0.18		19
20	Transmission	0.17		20
21				21
22	Energy Rates ($ per kWh)			22
23	Summer CPP			23
24	Secondary		1.19917	24
25	Primary		1.15192	25
26	Secondary Substation		1.19917	26
27	Primary Substation		1.15192	27
28	Transmission		1.12242	28
29	Summer On-Peak			29
30	Secondary	0.09245	0.08480	30
31	Primary	0.09103	0.08338	31
32	Secondary Substation	0.09245	0.08480	32
33	Primary Substation	0.09103	0.08338	33
34	Transmission	0.08946	0.08181	34
35	Summer Semi-Peak			35
36	Secondary	0.07491	0.06726	36
37	Primary	0.07372	0.06607	37
38	Secondary Substation	0.07491	0.06726	38
39	Primary Substation	0.07372	0.06607	39
40	Transmission	0.07253	0.06488	40
41	Summer Off-Peak			41
42	Secondary	0.05639	0.04987	42
43	Primary	0.05534	0.04894	43
44	Secondary Substation	0.05639	0.04987	44
45	Primary Substation	0.05534	0.04894	45
46	Transmission	0.05461	0.04829	46
47	Winter On-Peak			47
48	Secondary	0.09083	0.08318	48
49	Primary	0.08946	0.08181	49
50	Secondary Substation	0.09083	0.08318	50
51	Primary Substation	0.08946	0.08181	51
52	Transmission	0.08787	0.08022	52
53	Winter Semi-Peak			53
54	Secondary	0.08351	0.07586	54
55	Primary	0.08217	0.07452	55
56	Secondary Substation	0.08351	0.07586	56
57	Primary Substation	0.08217	0.07452	57
58	Transmission	0.08087	0.07321	58
59	Winter Off-Peak			59
60	Secondary	0.06223	0.05503	60
61	Primary	0.06106	0.05400	61
62	Secondary Substation	0.06223	0.05503	62
63	Primary Substation	0.06106	0.05400	63
64	Transmission	0.06026	0.05329	64

Attachment JRM 10-1.2
SAN DIEGO GAS & ELECTRIC COMPANY
DEFAULT CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule A6-TOU	(B) Proposed Default CPP Rates	Line #
1	Capacity Reservation Charge ($ per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Maximum On-Peak Demand: Summer			9
10	Primary	7.15		10
11	Primary Substation	7.15		11
12	Transmission	6.98		12
13	Maximum On-Peak Demand: Winter			13
14	Primary	0.05		14
15	Primary Substation	0.05		15
16	Transmission	0.05		16
17				17
18	Energy Rates ($ per kWh)			18
19	Summer CPP			19
20	Secondary		1.19917	20
21	Primary		1.15192	21
22	Secondary Substation		1.19917	22
23	Primary Substation		1.15192	23
24	Transmission		1.12242	24
25	Summer On-Peak			25
26	Secondary	0.09245	0.08480	26
27	Primary	0.09103	0.08338	27
28	Secondary Substation	0.09245	0.08480	28
29	Primary Substation	0.09103	0.08338	29
30	Transmission	0.08946	0.08181	30
31	Summer Semi-Peak			31
32	Secondary	0.07491	0.06726	32
33	Primary	0.07372	0.06607	33
34	Secondary Substation	0.07491	0.06726	34
35	Primary Substation	0.07372	0.06607	35
36	Transmission	0.07253	0.06488	36
37	Summer Off-Peak			37
38	Secondary	0.05639	0.04987	38
39	Primary	0.05534	0.04894	39
40	Secondary Substation	0.05639	0.04987	40
41	Primary Substation	0.05534	0.04894	41
42	Transmission	0.05461	0.04829	42
43	Winter On-Peak			43
44	Secondary	0.09083	0.08318	44
45	Primary	0.08946	0.08181	45
46	Secondary Substation	0.09083	0.08318	46
47	Primary Substation	0.08946	0.08181	47
48	Transmission	0.08787	0.08022	48
49	Winter Semi-Peak			49
50	Secondary	0.08351	0.07586	50
51	Primary	0.08217	0.07452	51
52	Secondary Substation	0.08351	0.07586	52
53	Primary Substation	0.08217	0.07452	53
54	Transmission	0.08087	0.07321	54
55	Winter Off-Peak			55
56	Secondary	0.06223	0.05503	56
57	Primary	0.06106	0.05400	57
58	Secondary Substation	0.06223	0.05503	58
59	Primary Substation	0.06106	0.05400	59
60	Transmission	0.06026	0.05329	60

Attachment JRM 10-1.3
SAN DIEGO GAS & ELECTRIC COMPANY
DEFAULT CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule PA-T-1	(B) Proposed Default CPP Rates	Line #
1	Capacity Reservation Charge ($ per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Demand Summer			9
10	Option D			10
11	Secondary	6.02		11
12	Primary	5.93		12
13	Transmission	5.79		13
14	Demand Winter			14
15	Option D			15
16	Secondary	0.19		16
17	Primary	0.19		17
18	Transmission	0.19		18
19				19
20	Energy Rates ($ per kWh)			20
21	Summer CPP			21
22	Secondary		1.19917	22
23	Primary		1.15192	23
24	Secondary Substation		1.19917	24
25	Primary Substation		1.15192	25
26	Transmission		1.12242	26
27	Summer On-Peak			27
28	Secondary	0.09245	0.08480	28
29	Primary	0.09103	0.08338	29
30	Secondary Substation	0.09245	0.08480	30
31	Primary Substation	0.09103	0.08338	31
32	Transmission	0.08946	0.08181	32
33	Summer Semi-Peak			33
34	Secondary	0.07491	0.06726	34
35	Primary	0.07372	0.06607	35
36	Secondary Substation	0.07491	0.06726	36
37	Primary Substation	0.07372	0.06607	37
38	Transmission	0.07253	0.06488	38
39	Summer Off-Peak			39
40	Secondary	0.05639	0.04987	40
41	Primary	0.05534	0.04894	41
42	Secondary Substation	0.05639	0.04987	42
43	Primary Substation	0.05534	0.04894	43
44	Transmission	0.05461	0.04829	44
45	Winter On-Peak			45
46	Secondary	0.09083	0.08318	46
47	Primary	0.08946	0.08181	47
48	Secondary Substation	0.09083	0.08318	48
49	Primary Substation	0.08946	0.08181	49
50	Transmission	0.08787	0.08022	50
51	Winter Semi-Peak			51
52	Secondary	0.08351	0.07586	52
53	Primary	0.08217	0.07452	53
54	Secondary Substation	0.08351	0.07586	54
55	Primary Substation	0.08217	0.07452	55
56	Transmission	0.08087	0.07321	56
57	Winter Off-Peak			57
58	Secondary	0.06223	0.05503	58
59	Primary	0.06106	0.05400	59
60	Secondary Substation	0.06223	0.05503	60
61	Primary Substation	0.06106	0.05400	61
62	Transmission	0.06026	0.05329	62

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JRM 10-2

Attachment JRM 10-2

Proposed Default CPP Bill Impacts
Customers with Demand 20 kW or Greater

Percent Bill Impact	Number of Accounts
-22.5% to -20.0%	1
-20.0% to -17.5%	1
-15.0% to -12.5%	4
-12.5% to -10.0%	16
-10.0% to -7.5%	43
-7.5% to -5.0%	193
-5.0% to -2.5%	379
-2.5% to 0.0%	1038
0.0% to 2.5%	644
2.5% to 5.0%	121
5.0% to 7.5%	19
7.5% to 10.0%	5
10.0% to 12.5%	4
12.5% to 15.0%	1
27.5% to 30.0%	1

ATTACHMENT

JRM 10-3

Attachment JRM 10-3.1
SAN DIEGO GAS & ELECTRIC COMPANY
VOLUNTARY CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule AL-TOU	(B) Proposed Voluntary CPP Rates	Line #
1	Capacity Rates ($ per kW)			1
2	Demand: Summer			2
3	Secondary	5.64		3
4	Primary	5.56		4
5	Secondary Substation	5.64		5
6	Primary Substation	5.56		6
7	Transmission	5.43		7
8	Demand: Winter			8
9	Secondary	0.18		9
10	Primary	0.18		10
11	Secondary Substation	0.18		11
12	Primary Substation	0.18		12
13	Transmission	0.17		13
14				14
15	Energy Rates ($ per kWh)			15
16	Summer CPP Period 1			16
17	Secondary		1.01817	17
18	Primary		1.00398	18
19	Secondary Substation		1.01817	19
20	Primary Substation		1.00398	20
21	Transmission		0.98834	21
22	Summer CPP Period 2			22
23	Secondary		0.46824	23
24	Primary		0.46231	24
25	Secondary Substation		0.46824	25
26	Primary Substation		0.46231	26
27	Transmission		0.45635	27
28	Summer On-Peak			28
29	Secondary	0.09245	0.09245	29
30	Primary	0.09103	0.09103	30
31	Secondary Substation	0.09245	0.09245	31
32	Primary Substation	0.09103	0.09103	32
33	Transmission	0.08946	0.08946	33
34	Summer Semi-Peak			34
35	Secondary	0.07491	0.07491	35
36	Primary	0.07372	0.07372	36
37	Secondary Substation	0.07491	0.07491	37
38	Primary Substation	0.07372	0.07372	38
39	Transmission	0.07253	0.07253	39
40	Summer Off-Peak			40
41	Secondary	0.05639	0.05639	41
42	Primary	0.05534	0.05534	42
43	Secondary Substation	0.05639	0.05639	43
44	Primary Substation	0.05534	0.05534	44
45	Transmission	0.05461	0.05461	45
46	Winter On-Peak			46
47	Secondary	0.09083	0.09083	47
48	Primary	0.08946	0.08946	48
49	Secondary Substation	0.09083	0.09083	49
50	Primary Substation	0.08946	0.08946	50
51	Transmission	0.08787	0.08787	51
52	Winter Semi-Peak			52
53	Secondary	0.08351	0.08351	53
54	Primary	0.08217	0.08217	54
55	Secondary Substation	0.08351	0.08351	55
56	Primary Substation	0.08217	0.08217	56
57	Transmission	0.08087	0.08087	57
58	Winter Off-Peak			58
59	Secondary	0.06223	0.06223	59
60	Primary	0.06106	0.06106	60
61	Secondary Substation	0.06223	0.06223	61
62	Primary Substation	0.06106	0.06106	62
63	Transmission	0.06026	0.06026	63

Attachment JRM 10-3.2

SAN DIEGO GAS & ELECTRIC COMPANY

VOLUNTARY CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule A6-TOU	(B) Proposed Voluntary CPP Rates	Line #
1	Capacity Rates ($ per kW)			1
2	Maximum On-Peak Demand: Summer			2
3	Primary	7.15		3
4	Primary Substation	7.15		4
5	Transmission	6.98		5
6	Maximum On-Peak Demand: Winter			6
7	Primary	0.05		7
8	Primary Substation	0.05		8
9	Transmission	0.05		9
10				10
11	Energy Rates ($ per kWh)			11
12	Summer CPP Period 1			12
13	Secondary		1.01817	13
14	Primary		1.00398	14
15	Secondary Substation		1.01817	15
16	Primary Substation		1.00398	16
17	Transmission		0.98834	17
18	Summer CPP Period 2			18
19	Secondary		0.46824	19
20	Primary		0.46231	20
21	Secondary Substation		0.46824	21
22	Primary Substation		0.46231	22
23	Transmission		0.45635	23
24	Summer On-Peak			24
25	Secondary	0.09245	0.09245	25
26	Primary	0.09103	0.09103	26
27	Secondary Substation	0.09245	0.09245	27
28	Primary Substation	0.09103	0.09103	28
29	Transmission	0.08946	0.08946	29
30	Summer Semi-Peak			30
31	Secondary	0.07491	0.07491	31
32	Primary	0.07372	0.07372	32
33	Secondary Substation	0.07491	0.07491	33
34	Primary Substation	0.07372	0.07372	34
35	Transmission	0.07253	0.07253	35
36	Summer Off-Peak			36
37	Secondary	0.05639	0.05639	37
38	Primary	0.05534	0.05534	38
39	Secondary Substation	0.05639	0.05639	39
40	Primary Substation	0.05534	0.05534	40
41	Transmission	0.05461	0.05461	41
42	Winter On-Peak			42
43	Secondary	0.09083	0.09083	43
44	Primary	0.08946	0.08946	44
45	Secondary Substation	0.09083	0.09083	45
46	Primary Substation	0.08946	0.08946	46
47	Transmission	0.08787	0.08787	47
48	Winter Semi-Peak			48
49	Secondary	0.08351	0.08351	49
50	Primary	0.08217	0.08217	50
51	Secondary Substation	0.08351	0.08351	51
52	Primary Substation	0.08217	0.08217	52
53	Transmission	0.08087	0.08087	53
54	Winter Off-Peak			54
55	Secondary	0.06223	0.06223	55
56	Primary	0.06106	0.06106	56
57	Secondary Substation	0.06223	0.06223	57
58	Primary Substation	0.06106	0.06106	58
59	Transmission	0.06026	0.06026	59

Attachment JRM 10-3.3
SAN DIEGO GAS & ELECTRIC COMPANY
VOLUNTARY CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule PA-T-1	(B) Proposed Voluntary CPP Rates	Line #
1	Capacity Rates ($ per kW)			1
2	Demand Summer			2
3	Option D			3
4	Secondary	6.02		4
5	Primary	5.93		5
6	Transmission	5.79		6
7	Demand Winter			7
8	Option D			8
9	Secondary	0.19		9
10	Primary	0.19		10
11	Transmission	0.19		11
12				12
13	Energy Rates ($ per kWh)			13
14	Summer CPP Period 1			14
15	Secondary		1.01817	15
16	Primary		1.00398	16
17	Secondary Substation		1.01817	17
18	Primary Substation		1.00398	18
19	Transmission		0.98834	19
20	Summer CPP Period 2			20
21	Secondary		0.46824	21
22	Primary		0.46231	22
23	Secondary Substation		0.46824	23
24	Primary Substation		0.46231	24
25	Transmission		0.45635	25
26	Summer On-Peak			26
27	Secondary	0.09245	0.09245	27
28	Primary	0.09103	0.09103	28
29	Secondary Substation	0.09245	0.09245	29
30	Primary Substation	0.09103	0.09103	30
31	Transmission	0.08946	0.08946	31
32	Summer Semi-Peak			32
33	Secondary	0.07491	0.07491	33
34	Primary	0.07372	0.07372	34
35	Secondary Substation	0.07491	0.07491	35
36	Primary Substation	0.07372	0.07372	36
37	Transmission	0.07253	0.07253	37
38	Summer Off-Peak			38
39	Secondary	0.05639	0.05639	39
40	Primary	0.05534	0.05534	40
41	Secondary Substation	0.05639	0.05639	41
42	Primary Substation	0.05534	0.05534	42
43	Transmission	0.05461	0.05461	43
44	Winter On-Peak			44
45	Secondary	0.09083	0.09083	45
46	Primary	0.08946	0.08946	46
47	Secondary Substation	0.09083	0.09083	47
48	Primary Substation	0.08946	0.08946	48
49	Transmission	0.08787	0.08787	49
50	Winter Semi-Peak			50
51	Secondary	0.08351	0.08351	51
52	Primary	0.08217	0.08217	52
53	Secondary Substation	0.08351	0.08351	53
54	Primary Substation	0.08217	0.08217	54
55	Transmission	0.08087	0.08087	55
56	Winter Off-Peak			56
57	Secondary	0.06223	0.06223	57
58	Primary	0.06106	0.06106	58
59	Secondary Substation	0.06223	0.06223	59
60	Primary Substation	0.06106	0.06106	60
61	Transmission	0.06026	0.06026	61

Attachment JRM 10-3.4
SAN DIEGO GAS & ELECTRIC COMPANY
VOLUNTARY CPP COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Present Rates Applicable to Schedule Voluntary CPP	(B) Proposed Voluntary CPP Rates	Line #
1	Energy Rates ($ per kWh)			1
2	Summer CPP Period 1			2
3	Secondary	1.44110	1.01817	3
4	Primary	1.44110	1.00398	4
5	Secondary Substation	1.44110	1.01817	5
6	Primary Substation	1.44110	1.00398	6
7	Transmission	1.44110	0.98834	7
8	Summer CPP Period 2			8
9	Secondary	0.42550	0.46824	9
10	Primary	0.42550	0.46231	10
11	Secondary Substation	0.42550	0.46824	11
12	Primary Substation	0.42550	0.46231	12
13	Transmission	0.42550	0.45635	13
14	Summer On-Peak			14
15	Secondary	0.13401	0.09245	15
16	Primary	0.13401	0.09103	16
17	Secondary Substation	0.13401	0.09245	17
18	Primary Substation	0.13401	0.09103	18
19	Transmission	0.13401	0.08946	19
20	Summer Semi-Peak			20
21	Secondary	0.07500	0.07491	21
22	Primary	0.07500	0.07372	22
23	Secondary Substation	0.07500	0.07491	23
24	Primary Substation	0.07500	0.07372	24
25	Transmission	0.07500	0.07253	25
26	Summer Off-Peak			26
27	Secondary	0.04954	0.05639	27
28	Primary	0.04954	0.05534	28
29	Secondary Substation	0.04954	0.05639	29
30	Primary Substation	0.04954	0.05534	30
31	Transmission	0.04954	0.05461	31
32	Winter On-Peak			32
33	Secondary	0.13401	0.09083	33
34	Primary	0.13401	0.08946	34
35	Secondary Substation	0.13401	0.09083	35
36	Primary Substation	0.13401	0.08946	36
37	Transmission	0.13401	0.08787	37
38	Winter Semi-Peak			38
39	Secondary	0.07500	0.08351	39
40	Primary	0.07500	0.08217	40
41	Secondary Substation	0.07500	0.08351	41
42	Primary Substation	0.07500	0.08217	42
43	Transmission	0.07500	0.08087	43
44	Winter Off-Peak			44
45	Secondary	0.04954	0.06223	45
46	Primary	0.04954	0.06106	46
47	Secondary Substation	0.04954	0.06223	47
48	Primary Substation	0.04954	0.06106	48
49	Transmission	0.04954	0.06026	49

ATTACHMENT

JRM 10-4

Attachment JRM 10-4.1
SAN DIEGO GAS & ELECTRIC COMPANY
CPP-E COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule AL-TOU	(B) Proposed CPP-E Rates	Line #
1	Capacity Reservation Charge ($/kW per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Demand: Summer			9
10	Secondary	5.64		10
11	Primary	5.56		11
12	Secondary Substation	5.64		12
13	Primary Substation	5.56		13
14	Transmission	5.43		14
15	Demand: Winter			15
16	Secondary	0.18		16
17	Primary	0.18		17
18	Secondary Substation	0.18		18
19	Primary Substation	0.18		19
20	Transmission	0.17		20
21				21
22	Energy Rates ($ per kWh)			22
23	Summer CPP			23
24	Secondary		2.21876	24
25	Primary		2.13526	25
26	Secondary Substation		2.21876	26
27	Primary Substation		2.13526	27
28	Transmission		2.08361	28
29	Summer On-Peak			29
30	Secondary	0.09245	0.08176	30
31	Primary	0.09103	0.08050	31
32	Secondary Substation	0.09245	0.08176	32
33	Primary Substation	0.09103	0.08050	33
34	Transmission	0.08946	0.07912	34
35	Summer Semi-Peak			35
36	Secondary	0.07491	0.06625	36
37	Primary	0.07372	0.06520	37
38	Secondary Substation	0.07491	0.06625	38
39	Primary Substation	0.07372	0.06520	39
40	Transmission	0.07253	0.06414	40
41	Summer Off-Peak			41
42	Secondary	0.05639	0.04987	42
43	Primary	0.05534	0.04894	43
44	Secondary Substation	0.05639	0.04987	44
45	Primary Substation	0.05534	0.04894	45
46	Transmission	0.05461	0.04829	46
47	Winter On-Peak			47
48	Secondary	0.09083	0.08033	48
49	Primary	0.08946	0.07912	49
50	Secondary Substation	0.09083	0.08033	50
51	Primary Substation	0.08946	0.07912	51
52	Transmission	0.08787	0.07771	52
53	Winter Semi-Peak			53
54	Secondary	0.08351	0.07385	54
55	Primary	0.08217	0.07267	55
56	Secondary Substation	0.08351	0.07385	56
57	Primary Substation	0.08217	0.07267	57
58	Transmission	0.08087	0.07151	58
59	Winter Off-Peak			59
60	Secondary	0.06223	0.05503	60
61	Primary	0.06106	0.05400	61
62	Secondary Substation	0.06223	0.05503	62
63	Primary Substation	0.06106	0.05400	63
64	Transmission	0.06026	0.05329	64

Attachment JRM 10-4.2
SAN DIEGO GAS & ELECTRIC COMPANY
CPP-E COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule A6-TOU	(B) Proposed CPP-E Rates	Line #
1	Capacity Reservation Charge ($ per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Maximum On-Peak Demand: Summer			9
10	Primary	7.15		10
11	Primary Substation	7.15		11
12	Transmission	6.98		12
13	Maximum On-Peak Demand: Winter			13
14	Primary	0.05		14
15	Primary Substation	0.05		15
16	Transmission	0.05		16
17				17
18	Energy Rates ($ per kWh)			18
19	Summer CPP			19
20	Secondary		2.21876	20
21	Primary		2.13526	21
22	Secondary Substation		2.21876	22
23	Primary Substation		2.13526	23
24	Transmission		2.08361	24
25	Summer On-Peak			25
26	Secondary	0.09245	0.08176	26
27	Primary	0.09103	0.08050	27
28	Secondary Substation	0.09245	0.08176	28
29	Primary Substation	0.09103	0.08050	29
30	Transmission	0.08946	0.07912	30
31	Summer Semi-Peak			31
32	Secondary	0.07491	0.06625	32
33	Primary	0.07372	0.06520	33
34	Secondary Substation	0.07491	0.06625	34
35	Primary Substation	0.07372	0.06520	35
36	Transmission	0.07253	0.06414	36
37	Summer Off-Peak			37
38	Secondary	0.05639	0.04987	38
39	Primary	0.05534	0.04894	39
40	Secondary Substation	0.05639	0.04987	40
41	Primary Substation	0.05534	0.04894	41
42	Transmission	0.05461	0.04829	42
43	Winter On-Peak			43
44	Secondary	0.09083	0.08033	44
45	Primary	0.08946	0.07912	45
46	Secondary Substation	0.09083	0.08033	46
47	Primary Substation	0.08946	0.07912	47
48	Transmission	0.08787	0.07771	48
49	Winter Semi-Peak			49
50	Secondary	0.08351	0.07385	50
51	Primary	0.08217	0.07267	51
52	Secondary Substation	0.08351	0.07385	52
53	Primary Substation	0.08217	0.07267	53
54	Transmission	0.08087	0.07151	54
55	Winter Off-Peak			55
56	Secondary	0.06223	0.05503	56
57	Primary	0.06106	0.05400	57
58	Secondary Substation	0.06223	0.05503	58
59	Primary Substation	0.06106	0.05400	59
60	Transmission	0.06026	0.05329	60

Attachment JRM 10-4.3
SAN DIEGO GAS & ELECTRIC COMPANY
CPP-E COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Proposed Rates Applicable to Schedule PA-T-1	(B) Proposed CPP-E Rates	Line #
1	Capacity Reservation Charge ($ per Month)			1
2	Secondary		7.07	2
3	Primary		6.71	3
4	Secondary Substation		7.07	4
5	Primary Substation		6.71	5
6	Transmission		6.45	6
7				7
8	Capacity Rates ($ per kW)			8
9	Demand Summer			9
10	Option D			10
11	Secondary	6.02		11
12	Primary	5.93		12
13	Transmission	5.79		13
14	Demand Winter			14
15	Option D			15
16	Secondary	0.19		16
17	Primary	0.19		17
18	Transmission	0.19		18
19				19
20	Energy Rates ($ per kWh)			20
21	Summer CPP			21
22	Secondary		2.21876	22
23	Primary		2.13526	23
24	Secondary Substation		2.21876	24
25	Primary Substation		2.13526	25
26	Transmission		2.08361	26
27	Summer On-Peak			27
28	Secondary	0.09245	0.08176	28
29	Primary	0.09103	0.08050	29
30	Secondary Substation	0.09245	0.08176	30
31	Primary Substation	0.09103	0.08050	31
32	Transmission	0.08946	0.07912	32
33	Summer Semi-Peak			33
34	Secondary	0.07491	0.06625	34
35	Primary	0.07372	0.06520	35
36	Secondary Substation	0.07491	0.06625	36
37	Primary Substation	0.07372	0.06520	37
38	Transmission	0.07253	0.06414	38
39	Summer Off-Peak			39
40	Secondary	0.05639	0.04987	40
41	Primary	0.05534	0.04894	41
42	Secondary Substation	0.05639	0.04987	42
43	Primary Substation	0.05534	0.04894	43
44	Transmission	0.05461	0.04829	44
45	Winter On-Peak			45
46	Secondary	0.09083	0.08033	46
47	Primary	0.08946	0.07912	47
48	Secondary Substation	0.09083	0.08033	48
49	Primary Substation	0.08946	0.07912	49
50	Transmission	0.08787	0.07771	50
51	Winter Semi-Peak			51
52	Secondary	0.08351	0.07385	52
53	Primary	0.08217	0.07267	53
54	Secondary Substation	0.08351	0.07385	54
55	Primary Substation	0.08217	0.07267	55
56	Transmission	0.08087	0.07151	56
57	Winter Off-Peak			57
58	Secondary	0.06223	0.05503	58
59	Primary	0.06106	0.05400	59
60	Secondary Substation	0.06223	0.05503	60
61	Primary Substation	0.06106	0.05400	61
62	Transmission	0.06026	0.05329	62

Attachment JRM 10-4.4
SAN DIEGO GAS & ELECTRIC COMPANY
CPP-E COMMODITY RATES FOR COMMERCIAL & INDUSTRIAL (> 20 kW)

Line #		(A) Present Rates Applicable to Schedule CPP-E	(B) Proposed CPP-E Rates	Line #
1	Energy Rates ($ per kWh)			1
2	Summer CPP			2
3	Secondary	3.45000	2.21876	3
4	Primary	3.45000	2.13526	4
5	Secondary Substation	3.45000	2.21876	5
6	Primary Substation	3.45000	2.13526	6
7	Transmission	3.45000	2.08361	7
8	Summer On-Peak			8
9	Secondary	0.12140	0.08176	9
10	Primary	0.12140	0.08050	10
11	Secondary Substation	0.12140	0.08176	11
12	Primary Substation	0.12140	0.08050	12
13	Transmission	0.12140	0.07912	13
14	Summer Semi-Peak			14
15	Secondary	0.06239	0.06625	15
16	Primary	0.06239	0.06520	16
17	Secondary Substation	0.06239	0.06625	17
18	Primary Substation	0.06239	0.06520	18
19	Transmission	0.06239	0.06414	19
20	Summer Off-Peak			20
21	Secondary	0.03693	0.04987	21
22	Primary	0.03693	0.04894	22
23	Secondary Substation	0.03693	0.04987	23
24	Primary Substation	0.03693	0.04894	24
25	Transmission	0.03693	0.04829	25
26	Winter On-Peak			26
27	Secondary	0.12140	0.08033	27
28	Primary	0.12140	0.07912	28
29	Secondary Substation	0.12140	0.08033	29
30	Primary Substation	0.12140	0.07912	30
31	Transmission	0.12140	0.07771	31
32	Winter Semi-Peak			32
33	Secondary	0.06239	0.07385	33
34	Primary	0.06239	0.07267	34
35	Secondary Substation	0.06239	0.07385	35
36	Primary Substation	0.06239	0.07267	36
37	Transmission	0.06239	0.07151	37
38	Winter Off-Peak			38
39	Secondary	0.03693	0.05503	39
40	Primary	0.03693	0.05400	40
41	Secondary Substation	0.03693	0.05503	41
42	Primary Substation	0.03693	0.05400	42
43	Transmission	0.03693	0.05329	43

ATTACHMENT

JRM 10-5

SAN DIEGO GAS & ELECTRIC COMPANY
PROPOSED SCHEDULE AS-TOU RATE STRUCTURE

LINE NO.	DESCRIPTION (A)	UNITS (B)	TRANSMISSION RATE (C)	DISTRIBUTION RATE (D)	PPP RATE (E)	ND RATE (F)	FTA RATE (G)	CTC RATE (H)	RS RATE (I)	TRAC RATE (J)	TOTAL UDC RATE (K)	EECC RATE (L)	DWR BOND RATE (M)	TOTAL RATE (N)	LINE NO.
1	**SCHEDULE A**														1
2	Basic Service Fee	$/Month	$0.00	$10.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.92			**10.92**	2
3	Energy Charge														3
4	Summer														4
5	Secondary	$/kWh	$0.01038	$0.05887	$0.00798	$0.00046	$0.00000	$0.00179	$0.00647	$0.00000	$0.08595	$0.10108	$0.00469	**0.19172**	5
6	Primary	$/kWh	$0.01038	$0.05357	$0.00798	$0.00046	$0.00000	$0.00179	$0.00647	$0.00000	$0.08065	$0.09934	$0.00469	**0.18468**	6
7	Winter														7
8	Secondary	$/kWh	$0.01038	$0.04802	$0.00798	$0.00046	$0.00000	$0.00179	$0.00647	$0.00000	$0.07510	$0.06917	$0.00469	**0.14896**	8
9	Primary	$/kWh	$0.01038	$0.04380	$0.00798	$0.00046	$0.00000	$0.00179	$0.00647	$0.00000	$0.07088	$0.06797	$0.00469	**0.14354**	9
10															10
11	**SCHEDULE AS-TOU**														11
12	Basic Service Fee														12
13	Less than or equal to 20 kW														13
14	Secondary	$/Month	$0.00	$10.92	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$10.92			**$10.92**	14
15	Primary	$/Month	0.00	10.92	0.00	0.00	0.00	0.00	0.00	0.00	10.92			**10.92**	15
16	Non-Coincident Demand														16
17	Secondary	$/kW	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.06			**0.06**	17
18	Primary	$/kW	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.06			**0.06**	18
19	Maximum On-Peak Demand: Summer														19
20	Secondary	$/kW	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.06		**0.10**	20
21	Primary	$/kW	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.06		**0.10**	21
22	Maximum On-Peak Demand: Winter														22
23	Secondary	$/kW	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.02		**0.05**	23
24	Primary	$/kW	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.02		**0.05**	24
25	On-Peak Energy: Summer														25
26	Secondary	$/kWh	0.01038	0.07377	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.10085	0.11613	0.00485	**0.22183**	26
27	Primary	$/kWh	0.01038	0.06847	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.09555	0.11439	0.00485	**0.21479**	27
28	Semi-Peak Energy: Summer														28
29	Secondary	$/kWh	0.01038	0.05826	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.08534	0.10062	0.00485	**0.19081**	29
30	Primary	$/kWh	0.01038	0.05317	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.08025	0.09908	0.00485	**0.18418**	30
31	Off-Peak Energy: Summer														31
32	Secondary	$/kWh	0.01038	0.04188	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.06896	0.08424	0.00485	**0.15805**	32
33	Primary	$/kWh	0.01038	0.03691	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.06399	0.08283	0.00485	**0.15167**	33
34	On-Peak Energy: Winter														34
35	Secondary	$/kWh	0.01038	0.06292	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.09000	0.08422	0.00485	**0.17907**	35
36	Primary	$/kWh	0.01038	0.05870	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.08578	0.08302	0.00485	**0.17365**	36
37	Semi-Peak Energy: Winter														37
38	Secondary	$/kWh	0.01038	0.05644	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.08352	0.07775	0.00485	**0.16612**	38
39	Primary	$/kWh	0.01038	0.05225	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.07933	0.07657	0.00485	**0.16075**	39
40	Off-Peak Energy: Winter														40
41	Secondary	$/kWh	0.01038	0.03762	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.06470	0.05893	0.00485	**0.12848**	41
42	Primary	$/kWh	0.01038	0.03358	0.00798	0.00046	0.00000	0.00179	0.00647	0.00000	0.06066	0.05790	0.00485	**0.12341**	34

ATTACHMENT

JRM 10-6

Attachment JRM 10-6

Proposed AS-TOU Bill Impacts
Customers with Demands Less Than 20 kW

Percent Bill Impact	Number of Accounts
-12.5% to -10.0%	808
-10.0% to -7.5%	3,804
-7.5% to -5.0%	10,576
-5.0% to -2.5%	26,324
-2.5% to 0.0%	29,894
0.0% to 2.5%	27,826
2.5% to 5.0%	9,550
5.0% to 7.5%	3,276

ATTACHMENT

JRM 10-7

Attachment JRM 10-7
Residential Peak Time Rebate (PTR) Calculation

Line	Description	Amount
1	Average Residential Hourly Class Load for the 9 CPP Days (kW)	1,205,486
2	Marginal Capacity Cost ($/kW-yr)	$76.4
3	CPP Marginal Cost Revenues (L1 * L2)	$92,099,130
4		
5	Residential Class Energy Use During 9 CPP Days (kWh)	75,945,617
6	Critical Peak Pricing Capacity Rate (L3 / L5)	$1.21270
7		
8	Less Proposed Summer Commodity Rate ($/kWh)	$0.09228
9		
10	Residential PTR Capacity Rate (L6 - L8)	$1.12042

ATTACHMENT

JRM 10-8

Seasonality and Time-Of-Use analysis for the Commercial and Residential Classes

Background

SDG&E has conducted an analysis of its seasonal periods for its Commercial loads to determine whether the month of October should be included in its definition of the commercial summer season. Currently, SDG&E defines its commercial summer season to include the months of May through September whereas the residential summer season is defined to be May through October. One of the goals of this analysis is to evaluate the current seasonal definition for SDG&E's commercial customers and provide a recommendation of whether October should be included in the commercial summer definition.

In addition to the seasonal analysis, SDG&E analyzed the traditional winter on-peak time-of-use period for its commercial customers. Currently, the on-peak time-of-use period for SDG&E's commercial class is from 5PM-8PM during the winter months.

Summary and Recommendations

October should be included as a summer month for SDG&E's commercial customers.

A variety of different analyses were performed in an attempt to identify whether October should be included as a summer month for the Commercial Class. First, peak system loads from October were identified and compared to other summer month. Second, a review was conducted for each month with respect to SDG&E's system peak time and that was compared to the commercial class peak time for all months of the year. Third, a population weighted twenty year average Cooling Degree Day analysis was conducted for each summer month. The data presented shows that the October month clearly should be classified as a summer month for all of SDG&E's customers.

Based on the results of these analyses, SDG&E recommends that it make the transition from a 5 month summer period to a 6 month summer period for its commercial class. This should be put into effect following the implementation of its Advanced Metering Infrastructure (AMI) implementation deployment. Making the transition after

AMI is implemented will ensure a fair and consistent rate structure for all of SDG&E's commercial customers. SDG&E expects that it will formally recommend this seasonal definition change the following year after all AMI meters are installed. All meters are projected to be installed by 2010, therefore SDG&E anticipates that the seasonal change will take effect on January 1st 2011.

The Commercial On-Peak winter periods should be changed to "semi-peak" and there should be no "on-peak" period for commercial customers during the winter months.

An analysis was performed to determine whether the current 5-8 winter on-peak period for commercial customers is appropriate and necessary. Monthly peak data for both the system and the commercial class was examined. The system peak data shows that although the winter monthly peaks occur between 5 p.m. - 8 p.m., the winter monthly peaks are nearly 800 MW lower than summer monthly peaks therefore load reduction is not needed during these time periods. In addition, the study of the commercial class monthly peak data shows that the commercial class peaks between 12 p.m. and 3 p.m. during the winter indicating that the 5 p.m. – 8 p.m. time period is not appropriate for this class of customers. This change is also supported by the fact that PG&E and SCE currently do not have a winter on-peak period for their commercial customers.

Analysis of the summer time period:

1. Frequency of occurrence by month for top 13 System Peak load days
2. Time of day for Monthly Peaks
3. Average monthly on-peak consumption of the commercial class
4. Monthly Cooling Degree Days (20 year population weighted average)

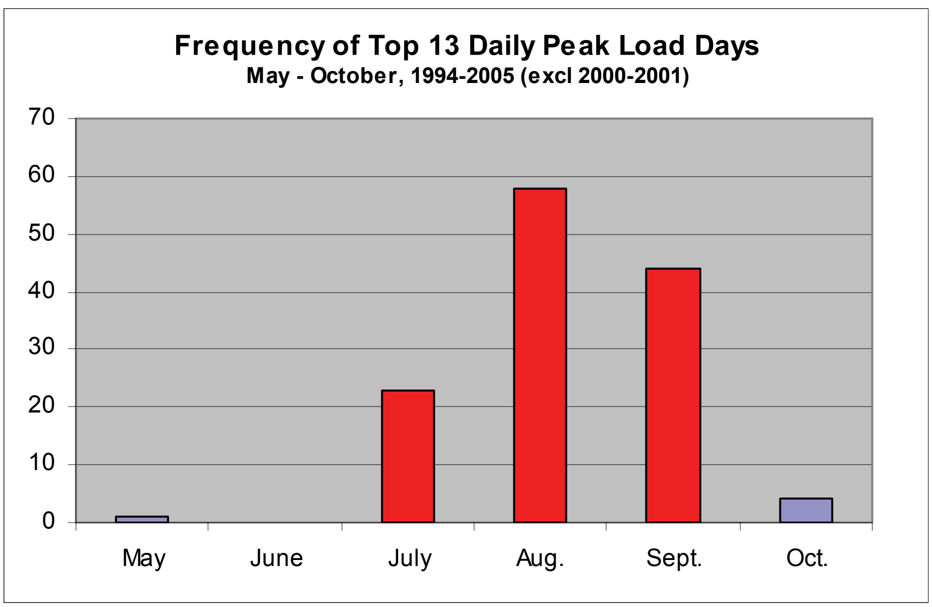
Analysis of winter TOU period

5. Winter commercial TOU period

1. Top 13 System Peak load days (by frequency of Occurrence)

A review of the top 13 daily system peak load days was performed over a 10 year period. This data is summarized below in Figure 1 to show the monthly frequency distribution. October has more peak load days than both the May and June months combined. The energy crisis years of 2000 and 2001 have been excluded from the analysis as conclusions drawn from those years have nothing to do with typical peak load conditions or weather patterns. The fact that some of SDG&E's top 13 load days occur in October is important for SDG&E's proposed default CPP rate. CPP events are normally called only during the summer period and including October in the summer period will ensure that SDG&E is able to call CPP events in October when system loads are high and it is necessary.

Figure 1



2. Time of day for Heat related Monthly Peaks

Another method of differentiating summer versus winter months is by looking at the time of the monthly system peak. In a summer month the system peak is normally between 11 a.m. and 6 pm, and for winter months the system peak usually occurs between 5pm and 8pm. October behaves like a summer month in this respect because all monthly system peaks during October occur between 11 a.m. and 6 p.m. Table 1 compares the October monthly peaks to the May monthly peaks and shows that in 4 out of the 5 years the monthly peak for October is higher than the monthly peak for the summer month of May. However, removing May from the summer time period is not recommended because the system peaks during May usually occur between 11 p.m. and 6 p.m. as well. Data used in the analysis is from the years 1999-2005 excluding 2000 and 2001.

Table 1				
System Monthly Peaks and Time for 1999, 2002-2005				
Date	**Year**	**Month**	**Hour DST**	**kW**
05/03/1999	1999	5	21	2588050
05/13/2002	2002	5	14	2773900
05/28/2003	2003	5	14	2909060
05/03/2004	2004	5	15	3886780
05/20/2005	2005	5	15	3040310
06/29/1999	1999	6	16	2880800
06/18/2002	2002	6	15	2835190
06/30/2003	2003	6	16	3069450
06/04/2004	2004	6	14	3115550
06/22/2005	2005	6	15	3172260
07/13/1999	1999	7	17	3575680
07/25/2002	2002	7	15	3253900
07/16/2003	2003	7	18	3390320
07/20/2004	2004	7	16	3873700
07/22/2005	2005	7	15	4057210
08/26/1999	1999	8	16	3538950
08/12/2002	2002	8	14	3186690
08/12/2003	2003	8	15	3803090
08/10/2004	2004	8	15	3676570
08/29/2005	2005	8	16	4031490
09/30/1999	1999	9	17	3527540
09/23/2002	2002	9	16	3571000
09/05/2003	2003	9	16	3937220
09/10/2004	2004	9	15	4065480
09/29/2005	2005	9	16	3734810
10/13/1999	1999	10	16	3274180
10/07/2002	2002	10	14	3014960
10/21/2003	2003	10	15	3604690
10/08/2004	2004	10	15	3161110
10/06/2005	2005	10	15	3463350

3. Analysis of On-Peak definition for summer commercial load

Another statistic which supports the definition of October as a summer month for the commercial class is to compare the level of on-peak load for commercial customers in October to the other months. Table 2 shows load data from the 2002-2005 Dynamic Load Profiles and it includes all customers except residential and lighting. The top 4 rows contain the average daily 11 a.m. – 6 p.m. consumption for each month, and the bottom four rows display the rank of each month within the year. Table 2 also shows that in all four years, the October consumption from 11 a.m. – 6 p.m. was within the top 6 months, and in 3 of the 4 years the on-peak consumption in October was higher than the on-peak consumption in May.

Table 2

Average Monthly Commercial Load and associated Rankings

Average on-peak commercial kWh	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2002	216961	223685	219339	227710	238815	256052	278478	289078	301153	265550	249644	233033
2003	251597	248401	251643	249048	257426	268018	299724	312416	312948	301630	262103	256031
2004	259274	254483	275889	270155	286947	290058	309175	311695	324963	280804	261081	252278
2005	254954	255452	261075	264621	275801	288586	306705	319772	303061	284986	270889	248074
Ranking of month within each year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2002	12	10	11	9	7	5	3	2	1	4	6	8
2003	10	12	9	11	7	5	4	2	1	3	6	8
2004	10	11	7	8	5	4	3	2	1	6	9	12
2005	11	10	9	8	6	4	2	1	3	5	7	12

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4. Monthly Cooling Degree Days (20 year population weighted average)

Finally, Figure 2 examines the 20 year population weighted Cooling-Degree Days (CDD) and the results show that October's CDD average is very similar to June and nearly twice as high as May. The monthly peaks in October are driven by warm weather. This analysis clearly shows that October weather is not different from June and on average October is warmer than May. October should be included in the definition for the commercial summer season. The CDD values for the months are located in Table 3.

Figure 2

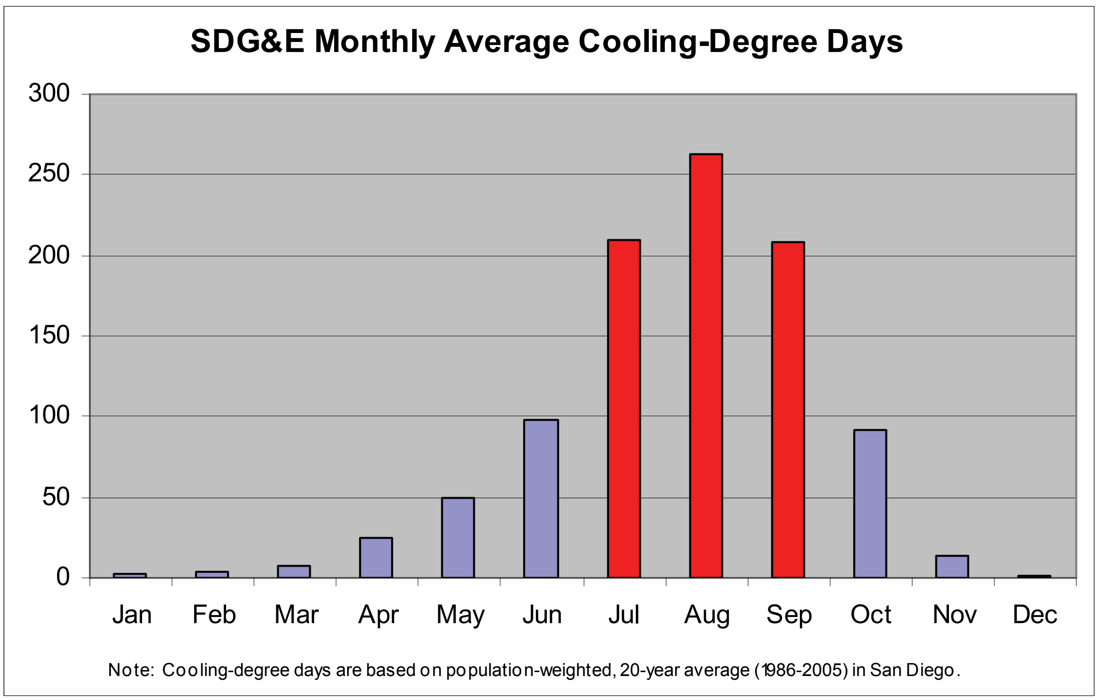

Table 3

(1986-2005)	Ave CDD
Jan	2.1
Feb	3.5
Mar	8.0
Apr	24.8
May	49.9
Jun	97.8
Jul	208.9
Aug	263.4
Sep	207.9
Oct	91.3
Nov	13.8
Dec	0.8

6. Winter TOU Period Commercial Class

In order to answer the question of whether a winter on-peak TOU period is necessary the system peaks during summer and winter were examined over a five year period. Table 4 presents an analysis that shows that the distance between the summer and winter peaks has grown from 445 MW in 1999 to 789 MW in 2005. The large differences between the summer and winter peaks show that it is highly unlikely for load reduction to be needed during the winter. Although it is true that 90% of monthly system peaks during this time period occur between 5 p.m. and 8 p.m., the large difference between the summer and winter peaks shows that the winter TOU on-peak period is not needed.

Table 4			
SDG&E System Peak Loads			
Year	Summer Peak	Winter Peak	Difference
1999	3576	3131	445
2002	3253	3039	214
2003	3937	3221	716
2004	4065	3217	848
2005	4057	3268	789

Further support for the elimination of the 5 p.m. – 8 p.m. winter TOU time period for the commercial class comes from a look at the monthly peaks for the commercial class alone. The results of examining the peaks for the years 1999 and 2002-2006 show that winter monthly peaks for the commercial class occur between 12 p.m. and 3 p.m. SDG&E's commercial class winter peaks ***are not*** coincident with the winter system peak. On the other hand the residential class usually peaks between 6 p.m. – 8 p.m. which is closer to the system peak time. SDG&E recommends that the 5 p.m. – 8 p.m. winter on-peak periods for the commercial class be eliminated.

ATTACHMENT

JRM 10-9

Attachment JRM 10-9

San Diego Gas & Electric
Analysis of Baseline Allowances

Based on Customer Usage Data for 2002-2005

Line No.	Season (A)	Service Type (B)	Climate Zone (C)	Present Baseline Allowance (kWh/Mo.) (D)	Percent of Average Residential Usage Under Present Baseline Allowance (E)	Baseline Guideline (% of Residential Usage) (F)	Deviation From Guideline (% of Residential Usage) (G)
1	Summer	Basic	Coastal	313	57%	60%	-2.7%
2			Inland	362	57%	60%	-2.8%
3			Mountain	475	56%	60%	-3.7%
4			Desert	531	56%	60%	-4.2%
5		All-Electric	Coastal*	301	71%	60%	11.0%
6			Inland*	356	62%	60%	1.8%
7			Mountain	564	59%	60%	-1.4%
8			Desert	598	56%	60%	-3.9%
9	Winter	Basic	Coastal	326	58%	60%	-1.9%
10			Inland	347	59%	60%	-1.2%
11			Mountain	440	57%	60%	-2.6%
12			Desert	362	59%	60%	-1.2%
13		All-Electric	Coastal*	501	82%	70%	11.7%
14			Inland*	576	74%	70%	4.1%
15			Mountain*	890	72%	70%	1.5%
16			Desert*	673	71%	70%	0.9%

*Exceeds statutory range

ATTACHMENT

JRM 10-10

Attachment JRM 10-10

Percentage of Seasonal Residences By Climate Zone

	Type of Service	
Climate Zone	**Basic Electric**	**All Electric**
Coastal	2.7%	4.9%
Inland	1.0%	2.2%
Mountain	10.7%	17.7%
Desert	0.0%	13.4%

ATTACHMENT

JRM 10-11

Attachment JRM 10-11

Impact of Seasonal Residences On Baseline Allowance Quantities

Type of Service (A)	Climate Zone (B)	Seasonal Residences Excluded (C)	Seasonal Residences Included (D)	Difference (E)	% Change (F)
			Summer		
Basic Electric:					
(kWh/Month)	Coastal	336	336	0	0.0%
	Inland	388	388	0	0.0%
	Mountain	523	520	(3)	(0.6%)
	Desert	599	599	0	0.0%
All Electric:					
(kWh/Month)	Coastal	231	229	(2)	(0.9%)
	Inland	340	340	0	0.0%
	Mountain	599	582	(17)	(2.8%)
	Desert	671	665	(6)	(0.9%)
			Winter		
Basic Electric:					
(kWh/Month)	Coastal	342	342	0	0.0%
	Inland	357	357	0	0.0%
	Mountain	469	468	(1)	(0.2%)
	Desert	374	374	0	0.0%
All Electric:					
(kWh/Month)	Coastal	352	351	(1)	(0.3%)
	Inland	508	508	0	0.0%
	Mountain	875	860	(15)	(1.7%)
	Desert	666	659	(7)	(1.1%)