Decision ___________________

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company For Authority to Make Various Electric Rate Design Changes, Close Certain Rates, and Revise Cost Allocation Among Customer Classes Effective August 1, 2001 (U 902-E).	Application 00-11-007 (Filed November 1, 2000)

O P I N I O N

This decision makes minor changes to San Diego Gas & Electric's rate design. There is no change to any electric customer rate class. All changes are revenue neutral within each class.

San Diego Gas & Electric Company (SDG&E) submits this rate design window (RDW) application in accordance with the schedule adopted in Decision (D.) 89-01-040, as amended by D.95-09-020. In this RDW application, SDG&E seeks authority to make various electric rate design changes, implement hourly billing, and modify specific tariff language, effective August 1, 2001.

SDG&E proposed to implement mandatory hourly billing as directed by the Commission in D.00-06-034.

After this application was submitted, the Commission issued D.01-05-032 in Application (A.) 00-07-055, and Senate Bill 5 of the First Extraordinary Session of 2000-2001 (SBX1 5) was enacted, as was AB X1 29.[1] Those items dealt with real-time meters and may affect the relief requested by SDG&E in this application. Consequently, the Presiding Administrative Law Judge invited parties to comment on the effect, or lack of effect, of those items on the relief requested. By way of background, SDG&E's year 2000 RDW application sought (among other relief) Commission authority to switch large customers to mandatory hourly pricing (as required by Ordering Paragraph 21 of D.00-06-034) on a phased schedule, beginning with customers with demand of 4500kW or above.

SDG&E was the only party that responded. It believes that D.01-05-037, SBX1 5, AB X1 29 and other recent legislation and Commission decisions have made SDG&E's RDW mandatory hourly billing proposal moot because: (1) SDG&E's commodity rates for small and large customers are frozen; (2) SDG&E does not receive hourly commodity prices from the Department of Water Resources (DWR); and (3) the Commission has already addressed (and continues to review) hourly billing and related issues in other state-wide proceedings. Accordingly, SDG&E argues, it is unnecessary and potentially confusing to rule on parallel issues in SDG&E's RDW.

Finally, as a practical matter, SDG&E says it cannot implement hourly billing at this time because the Legislature has frozen the commodity rates for all SDG&E customers at 6.5 cents per kilowatt-hour (kWh) and SDG&E is not

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[1] D.01-05-032 authorized SDG&E to install real-time electric meters for customers with peak demands of 100 kW or greater; SB X1 5 appropriated funds to reduce peak load energy usage; ABX1 29 ordered mandatory time-of-use (TOU) or real time pricing (RTP) metering for customers with 200kW peak demand or greater.

receiving the hourly commodity prices necessary for hourly billing. Until SDG&E's commodity rates are unfrozen, and the DWR begins providing commodity costs in hourly increments, SDG&E cannot implement meaningful hourly billing.

Based on SDG&E's uncontradicted statements regarding hourly billing, and in accord with SDG&E's request, we will disregard SDG&E's mandatory hourly billing initiative.

SDG&E also proposes to modify the Dynamic Load Profiles it uses to calculate Schedule PX (Price exchange) rates for large customers by excluding the load profiles of Direct Access (DA) customers. Bundled customers using over 50kW should have a separate DLP. However, because the PX is now out of operation and DWR does not provide hourly prices, it is unnecessary to consider these proposals.

SDG&E proposes rate design changes to residential TOU schedules including canceling one of the two options and making minor changes to medium and large commercial/industrial electric rate schedules. It proposes a separate treatment for revenues recorded in the schedule AV memorandum account.

SDG&E proposes no change to any electric customer rate class. All proposed changes are revenue neutral within each class.

EFFECT ON PRESENT AND PROPOSED ELECTRIC REVENUES
BY CUSTOMER CLASS

Line No.	Customer Class	Present Distribution Revenues ($000's)	Proposed Distribution Revenues ($000s)	Percentage Change (0%)
1.	Residential	264,885	264,885	0.00
2.	Small Commercial	82,930	82,930	0.00
3.	Medium & Large Comm'l/Industrial	174,924	174,924	0.00
4.	Agricultural	5,609	5,609	0.00
5.	Lighting	5,571	5,571	0.00
6.	System Total	533,919	533,919	0.00

A prehearing conference was held February 16, 2001 at which time all parties agreed to SDG&E's proposals subject to SDG&E's submission of proposed findings of fact. Those findings have been reviewed by the parties; no objections have been made. We have reviewed the proposed findings and adopt them as reasonable. There are no protests. A public hearing is not necessary.

Comments on Draft Decision

The draft decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. No comments were filed.

Findings of Fact

1. Both SDG&E and ORA premised their support of mandatory hourly pricing on the assumption that the California PX would continue to provide SDG&E with energy prices that vary from hour to hour.

2. The PX ceased operations on February 1, 2001.

3. The California DWR has procured electricity for SDG&E since February 7, 2001.

4. As of April 13, 2001, the DWR has provided no price differentiation in the bills it sends to SDG&E.

5. SDG&E requests authority to modify how it creates samples for its dynamic load profiles which are used to allocate the hourly costs of energy from the PX. Since the PX is out of operation and the DWR is not providing hourly prices, it is unnecessary to consider SDG&E's sampling proposals in this proceeding.

6. The decision in SDG&E's last RDW proceeding (D.00-12-058) ordered SDG&E to establish a memo account to record the revenues it collects from billing the Distribution Energy Rates for Primary and Secondary level service during the semi-peak and off-peak periods on Schedules A-VI and A-V2. The decision ordered SDG&E to propose a method for returning these funds to all large commercial/industrial customers.

7. SDG&E proposes to return these funds through a six-month rate reduction to medium and large commercial/industrial customers' distribution energy charges equal to the revenues SDG&E has collected from the semi-peak and off-peak distribution energy rates in Schedule A-VI and A-V2. SDG&E asked that this rate reduction be authorized in this proceeding and implemented via an Advice Letter filing 90 days after a decision is issued. This is reasonable.

8. No party objected to SDG&E's proposal for returning these funds to customers. The changes in rates as shown in attached Table IV-1 (Appendix A) are reasonable and should be adopted.

9. SDG&E also requests relatively minor rate design changes to its residential TOU tariffs, Schedules DR-TOU and DR-TOU-2. The rate design changes consist of setting the distribution energy charges of both residential TOU tariffs equal to Schedule DR non-baseline rates, and to provide the Schedule DR baseline allowance benefits through a separate Baseline Adjustment rate element. These rate design changes will eliminate the disparity between Schedule DR and residential TOU distribution rates, including the baseline allowance benefits. The proposed changes eliminate the need for SDG&E to offer both residential TOU tariffs. This proposal is reasonable.

10. SDG&E proposes to eliminate the redundant TOU option by: a) canceling Schedule DR-TOU on the effective date of a decision in this proceeding; b) transferring any customer taking service under Schedule DR-TOU to Schedule DR-TOU-2; and c) renaming “Schedule DR-TOU-2” to simply “Schedule DR-TOU.” This proposal is reasonable.

11. SDG&E has asked that the rate changes set forth in the attached Tables II-C and II-D (Appendix B) become effective 30 days after the effective date of a decision in this proceeding. No party has opposed this recommendation. It will be adopted.

Conclusions of Law

1. Given the absence of hourly pricing data, SDG&E’s recommendation to eliminate mandatory hourly billing for consideration in this proceeding is reasonable and should be adopted.

2. SDG&E’s proposal to change the way it creates samples for dynamic load profiles is tied to receiving hourly energy prices. Since the PX has ceased operation and the DWR is not providing hourly pricing detail at this time,

SDG&E's recommendation to abandon its proposal to change how it creates dynamic load profile samples is reasonable and should be adopted.

3. SDG&E's proposal to return funds in a memo account (which has recorded the revenues the company has collected as a result of billing the semi-peak and off-peak distribution energy rates on Schedules A-VI and A-V2) via a six-month rate reduction to medium and large commercial/industrial customers' distribution rates is reasonable and should be adopted.

4. SDG&E's proposal to change the rate design of its residential TOU schedules DR-TOU and DR-TOU-2 by setting the distribution energy charges of both tariffs equal to Schedule DR non-baseline rate is reasonable and should be adopted. SDG&E's proposal to provide the Schedule DR baseline allowance benefits through a separate Baseline Adjustment rate element is reasonable and should be adopted.

5. SDG&E's proposals to a)cancel Schedule DR-TOU on the effective date of a decision in this proceeding; b) transfer customers taking service under Schedule DR-TOU to Schedule DR-TOU-2; and c) rename "Schedule DR-TOU-2" to "Schedule DR-TOU" are reasonable and should be adopted.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company (SDG&E) is authorized to establish the rates set forth in Appendix A & B. Tariffs shall be filed on not less than five days notice to the commission and to the public.

2. SDG&E shall implement Conclusions of Law 3, 4, and 5 as set forth herein.

3. This proceeding is closed.

This order is effective today.

Dated ________________, at San Francisco, California.

APPENDIX A

APPENDIX B

Table II-C

Rule Proposed Changes

MULTI-FAMILY ACCOMMODATION:

1. An apartment building, duplex, court group, residential hotel, housing project, Mobilehome Park or any other group of permanent residential dwelling units located upon a single premises, providing the residential units therein meet the requirements for a single-family accommodation.

2. Multi-Family Accommodations do not include: hotels, motels, guest or resort ranches, marinas, tourist camps, recreational vehicle parks, campgrounds, halfway houses, rooming houses, boarding houses, institutions, dormitories, rest or nursing homes, **adult residential facilities and residential-care facilities for the elderly**, military barracks or similar enterprises which rent for either transient tenants or transient accommodations.

APPENDIX B

Table II-D

Rule 23 Proposed Changes to Pages 2 – 5 of 14 pages

B. Definitions (Continued)

3. Utility Customer

Someone who takes bundled services including all energy requirements from the Utility through the Power Exchange.

C. CTC Calculation

1. AB 1890 codifies principles and procedures for implementing a CTC, including the kinds of customers which will be exempt from the CTC. The Commission will determine the ultimate magnitude of the CTC, the appropriate mechanism for collection of the CTC, and the method of payment for customers as part of future Commission orders.

2. As provided herein, the charges of the Utility's rate schedules, contracts, or tariff options will contain a CTC component. The CTC shall be applied to each customer based on the amount of the customer's electricity consumption (i.e., all generation-related billing determinants used to determine a customer's bill), which is subject to changes occurring in the normal course of business as described in PU Code Section 371, whether such consumption is served by the Utility or an alternate supplier of electricity. Pursuant to Section 371 of the PU Code, changes occurring in the normal course of business are those resulting from changes in business cycles, termination of operations, departure from the Utility service territory, weather, reduced production, modifications to production equipment or operations, changes in production or manufacturing processes, fuel switching, including installation of fuel cells, enhancement or increased efficiency of equipment or performance of existing **~~self-generation~~** **self-cogeneration** equipment, replacement of existing cogeneration equipment with new power generation equipment of similar size as described elsewhere in this Rule, installation of demand-side management equipment or facilities, energy conservation efforts, or other similar factors. Further, the CTC cannot be avoided through the formation of a local publicly-owned electric corporation on or after December 20, 1995, or by annexation of any portion of the Utility's service territory by an existing local publicly-owned electric utility.

The billed CTC will be based on metered consumption. In cases where there is Departing Load, third party metering will be allowed subject to verification procedures sufficient to assure reliability of such consumption and/or information. Meter reliability would be pursuant to Utility's Rule 18 and the Direct Access Standards for Metering and Meter Data (DASMMD). Each party will be responsible for its own costs associated with the agreed upon verification process. If reliable metered consumption information is not made available to the Utility, the Utility will estimate the consumption based on that customer's historical load pursuant to this Rule at the time the customer discontinues or reduces its purchases from the Utility.

The billed CTC will be determined on a residual basis. The billed CTC for a billing period is the difference between Generation Revenue (which is determined by multiplying the Generation for the applicable rate schedule by the customer's consumption billing determinants) and the Power Exchange (PX) energy cost to serve the customer. The PX energy cost for the billing period is calculated based on the procedures adopted by the Commission in its Consolidated Ratesetting Decision. However, certain consumption, as defined in Sections 369 through 374 of the PU Code and detailed as follows will not be included in the billed CTC calculation:

a. The billed CTC Calculation shall not include consumption resulting from new customer load or incremental load of an existing customer where such consumption is served through a Direct Transaction and such transaction does not otherwise require the use of the Utility's transmission or distribution facilities.

b. Consumption served by nonmobile ~~**self-generation**~~ **self-cogeneratio**n or cogeneration capacity existing as of December 20, 1995, per Section 372(a)(1) of the PU Code:

The billed CTC calculation shall not include consumption served by:

(1) nonmobile on-site or over-the-fence ~~**self generation**~~ **self-cogeneration** or cogeneration capacity that was operational on or before December 20, 1995; or

(2) increases in the capacity of such facilities constructed by an entity owning or operating the facility resulting from:

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(a) the replacement of existing cogeneration equipment with new power generation equipment of a size which does not exceed 120 percent of the installed capacity existing as of December 20, 1995; or

(b) the installation of new or additional generation equipment or facilities such that the total capacity does not exceed 120 percent of the installed capacity as of December 20, 1995.

However, as all standby service is subject to CTC, the standby service for the first 20% of additional departing load is subject to CTC and subject to the provisions of Rate Schedule S.

Such consumption must be served on-site or served through an over-the-fence transaction between affiliated parties as defined in Section 372(a)(1) of the PU Code as allowed under PU Code Section 218, as this Section existed on December 20, 1995 regardless of the date by which such over-the-fence arrangement was made. Pursuant to Section 372(a)(1) of the PU Code, "affiliated" means any person or entity that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with another specified entity.

Consumption served through unaffiliated transactions entered into on or before December 20, 1995 will not be included in the billed CTC calculation. However, the billed CTC calculation prior to June 30, 2000 shall include consumption served by over-the-fence arrangements entered into after December 20, 1995 between unaffiliated parties.

c. Consumption served by nonmobile ~~**self-generation**~~ **self-cogeneration** or cogeneration capacity committed to construction as of December 20, 1995, per Section 372(a)(2) of the PU Code:

The billed CTC calculation shall not include consumption served by:

(1) on-site or over-the-fence nonmobile ~~**self-generation**~~ **self-cogeneration** or cogeneration projects that were committed to construction as of December 20, 1995, and are substantially operational as of January 1, 1998, or

(2) increases in the capacity of such facilities constructed by an entity owning or operating the facility resulting from:

(a) the replacement of existing cogeneration equipment with new power generation equipment of a size which does not exceed 120 percent of the installed capacity existing as of January 1, 1998; or

(b) the installation of new or additional generation equipment or facilities such that the total installed capacity does not exceed 120 percent of the installed capacity as of January 1, 1998.

However, as all standby service is subject to CTC, the standby service for the first 20% of additional departing load is subject to CTC and subject to the provisions of Rate Schedule S.

Such consumption must be served on-site or served through an over-the-fence arrangement between affiliated parties as defined in Section 372(a)(1) of the PU Code and as allowed under PU Code Section 218, as this Section existed on December 20, 1995. Pursuant to Section 372(a)(1) of the PU Code, “affiliated” means any person or entity that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with another specified entity. Consumption served through unaffiliated transactions entered into on or before December 20, 1995 will not be included in the billed CTC calculation. However, the billed CTC calculation prior to June 30, 2000 shall include consumption served by over-the-fence arrangements entered into after December 20, 1995 between unaffiliated parties.

d. After June 30, 2000, consumption served by an on-site or over-the-fence nonmobile ~~**self-generation**~~ **self-cogeneration** or cogeneration facility is not subject to the billed CTC calculation, per Section 372(a)(4) of the PU Code**.**

e. Consumption served by emergency generation equipment, per Section 372(a)(3) of the PU Code:

The billed CTC calculation shall not include consumption served by existing, new, or portable emergency generation equipment used during periods when the Utility’s service is unavailable, provided such equipment is not operated in parallel with the Utility's power grid except on a momentary basis.

f. Consumption served by nonmobile ~~**self-generation**~~ **self-cogeneration** or cogeneration facilities that became operational after December 20, 1995, per Sections 372(c)(1) and (2) of the PU Code.

Pursuant to the PU Code, prior to June 30, 2000, at the Utility's discretion, the Utility and other interested parties may file applications to exempt load served onsite, or under an over-the-fence arrangement between unaffiliated parties, by a nonmobile ~~**self-generation**~~ **self-cogeneration** or cogeneration facility. This shall apply to those facilities that became operational after December 20, 1995, or over the fence arrangements between unaffiliated parties entered into, after December 20, 1995.

g. Existing ~~**Self-generation**~~ **self-cogeneration** Deferral ("SGD") Agreements, per Section 372(b)(2) of the PU Code:

The billed CTC for the consumption that would have been served by a ~~**self-generation**~~ **self-cogeneration** or cogeneration facility, were it not deferred under the SGD Agreement, will be adjusted to reflect the level of Generation revenue that is embedded in such customer's SGD discounted rate. If the Agreement expires or is terminated and the customer: (i) engages in a Direct Transaction; or (ii) constructs a ~~**self-generation**~~ **self-cogeneration** or cogeneration facility of approximately the same capacity as the facility deferred; or (iii) takes bundled electric service from the Utility, such customer will continue to be billed under the above provision.

h. SGD Agreements under negotiation as of December 20, 1995, per Section 372(b)(1) of the PU Code:

When the Utility executes a SGD Agreement with customers where negotiations with the Utility for such Agreement were in progress on or before December 20, 1995, and the Utility and the customer executed a letter of intent or similar documentation, such customers shall have their CTC determined as described in the Section above, provided that upon conclusion of the negotiations the final Agreement is consistent with the letter of intent and the Commission approves the Agreement.

i. Irrigation districts, per Section 374(a)(1) of the PU Code:

In accordance with the PU Code, 110 megawatts of irrigation district load shall be allocated to the service territories of the three largest electrical utilities under the jurisdiction of the Commission based upon the ratio of the number of irrigation districts in the service territory of each Utility to the total number of irrigation districts in the service territories of all three utilities. The amount of load allocated to each Utility will be phased in over a five-year period beginning January 1, 1997, such that one-fifth of the allocation is allocated in each of the five years. Any unused allocation shall be carried over and added to the next year's allocation.

The load allocated to each Utility will be further allocated among the irrigation districts within the Utility's service territory with load between 8 and 40 megawatts. Such load shall be served by distribution facilities owned by or leased to the district. Further, load allocated as provided above shall be located within the boundaries of the affected irrigation district or within the boundaries specified in the service territory boundary agreement between the Utility and such irrigation district as it existed on December 20, 1995. In addition, at least 50 percent of each year's allocation shall be applied to pumping load used for agricultural purposes.

END OF APPENDIX B