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

Application No. 07-01-047
Exhibit No.: (SDG&E-______)

REBUTTAL TESTIMONY

OF SAN DIEGO GAS & ELECTRIC COMPANY

This Includes Rebuttal Testimonies of:

Steve Rahon
Edward Fong
Joseph S. Velasquez
David A. Borden
Thomas O. Bialek
Robert W. Hansen

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

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

Application No. 07-01-047
Exhibit No.: (SDG&E-______)

REBUTTAL TESTIMONY

OF STEVE RAHON

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

PREPARED REBUTTAL TESTIMONY

OF

STEVE RAHON

The purpose of my rebuttal testimony is to support the adoption of the settlement principles and framework (settlement) reached by 11 of the 13 active parties to this proceeding. The settlement principles and framework will be finalized and submitted by separate motion prior to hearings in this proceeding. The 11 parties that reached settlement (San Diego Gas and Electric, the Division of Ratepayer Advocates, Utility Consumer Action Network, California Large Energy Consumers Association, the Federal Executives Agencies, California Farm Bureau Federation, California Manufacturers & Technology Association, Vote Solar Initiative, Solar Alliance, California Street Lighting Association, and Building Owners and Managers) either support or agree not to oppose the settlement. The two active parties that did not sign-on to the settlement were the City of San Diego and Fuel Cell Energy. Fuel Cell Energy has limited their rebuttal testimony to the size limitation proposed in the new distributed generation-renewable (Schedule DG-R) tariff. The City of San Diego intends to litigate all their positions put forth in their prepared direct testimony. The settlement covers all areas of GRC Phase II including AB1X issues, revenue allocation, rate design, dynamic pricing, and Schedule DG-R.

All active parties spent countless hours negotiating in good faith to reach the compromise set forth in the settlement documents found at Attachment 1. Each party compromised from their originally filed position to reach a fair and reasonable outcome to the issues put forth in this case. The settlement should be viewed in its entirety and is not severable.

The settlement parties will ultimately request that the Commission adopt the settlement in its entirety, allowing the issues that have been identified for litigation to proceed along that path. The settlement parties have agreed to litigate the non-coincident distribution demand charge at dispute related to the Schedule DG-R and to set aside for briefing the AB1X issues not addressed by the settlement.

This concludes my prepared rebuttal testimony.

QUALIFICATIONS

My name is Steve Rahon. I am employed by the Sempra Energy Utilities, San Diego Gas and Electric (SDG&E) and Southern California Gas Company (SoCalGas). My business address is 8315 Century Park Court, San Diego, California 92123-1550. I became Director of Regulatory Policy and Analysis in Regulatory Affairs in May 2007. Prior to that, I was the Director of Tariffs and Regulatory Accounts in Regulatory Affairs since April 2002.

I received a Bachelor of Science degree in Accounting from California State University Long Beach in 1987. I began my career as an internal auditor at Pacific Enterprises and later transferred to SoCalGas prior to the Pacific Enterprises/Enova merger in 1998. In 1991, I began working for SoCalGas in Gas Accounting and held various positions of increasing responsibility in Regulatory Accounting, General Accounting, and Financial Planning. In 1998, I joined Regulatory Affairs as a Regulatory Case Manager.

I have testified previously before the Commission.

Attachment 1

SAN DIEGO GAS & ELECTRIC COMPANY
TY2008 GENERAL RATE CASE
PHASE 2 SETTLEMENT
September 24, 2007

No element of this Settlement shall be deemed precedential as to the Commission or any of the Parties, either in the context of this San Diego Gas & Electric (SDG&E) General Rate Case (GRC) Phase 2 proceeding or in any future proceeding, and no Party shall use the contents of this Settlement, or any documents, discussions or other communications related to this Settlement, against any other Party in future Commission proceedings.

Unless otherwise addressed in this Settlement, all assumptions shall be based on SDG&E's January 31, 2007 General Rate Case (GRC) Phase 2 as-served testimony.[1]

I. REVENUE ALLOCATION AND RATE DESIGN

A. General

1. For review in SDG&E's next full GRC Phase 2 or Rate Design Window Application following the filing described in Section II.9, *below*, SDG&E shall perform the analysis and studies described in Attachment A.

2. Avoided generation capacity shall be $67 per kW-year.

3. SDG&E shall adopt a sub-metering program substantially similar to the program adopted in Pacific Gas & Electric's (PG&E) General Rate Case Phase 2 decision, D.07-09-004 (PG&E Decision). To record incremental costs related to implementing sub-metering, SDG&E shall establish a Memorandum Account.

4. Within 6 months of SDG&E's implementation of the Commission decision in this GRC Phase 2 proceeding, SDG&E will work with the Farm Bureau to notify agricultural customers of potential rate options and offer to assist these Customers in evaluating potentially better rate options.

B. Revenue Allocation

1. Revenue Allocation shall be as described in Attachment B.

C. Residential Rate Design

1. Unless otherwise specified, AB1X issues shall be subject to briefing.

2. SDG&E shall withdraw its CARE proposal.

[1] Including any subsequent errata and updates made prior to September 4, 2007.

3. The Total Rate Adjustment Component (TRAC) will be eliminated as a separate line item on the residential customer bill. The TRAC charges will be included as a component within the Public Purpose Program (PPP) charges for billing purposes and remain a separate item in SDG&E's tariffs.

4. The Tier 4 and Tier 5 rates will be consolidated into a single Tier 4 rate. The differential between Tier 3 and Tier 4 will be at least 2 cents per kWh.

5. The methodology for inclusion of California Solar Initiative (CSI) costs into residential rates will be similar to that as adopted in the PG&E Decision.

6. On an as available basis, SDG&E will, without charge to the customer, install time of use (TOU) meters that are available in current inventory, or will become available as a result of meter change-outs of residential customer who install a new solar energy system (SES) after schedule DR-SES becomes effective. The time-of-use (TOU) rate schedules DR-TOU or DR-SES will be available to SES customers. If no TOU meters are available for new SES customers, the customer may remain on the otherwise applicable tariff (OAT), or choose to pay for a new TOU meter to enable a TOU rate.

D. Small Commercial Rate (<20kw) Design

1. The basic service fee will increase by no more than 5% from the current level.

2. SDG&E will retain the current Schedule A for small commercial customers, and will withdraw the TOU rate proposals. SDG&E will withdraw both its proposal to create schedule AS-TOU, and its proposal to shift schedule A-TOU customers with demands between 20 KW and 40 KW to schedule AL-TOU.

E. Commercial and Industrial Rate Design

1. The demand/energy rate structure applied to the Competition Transition Charge (CTC) will remain unchanged.

2. A modified rate design approach will be applied to the distribution revenue requirements associated with: the Self-Generation Incentive Program (SGIP), CSI, the Annual Earnings Assessment Proceeding (AEAP), demand response programs, and electric procurement administration costs.

    a. The intra-class allocation factors applied to these cost categories shall be as follows:

Schedule AL-TOU	91.2%
Schedule AD	0.9%
Schedule AY-TOU	2.9%

Schedule A6-TOU	2.8%
Schedule PA-T-1	1.8%
Schedule S	0.3%

b. Within Schedule AL-TOU the following allocation factors shall apply:

Schedule AL-TOU- Secondary	81.7%
Schedule AL-TOU- Primary	12.0%
Schedule AL-TOU- Sec. Substation	1.6%
Schedule AL-TOU- Pri. Substation	3.8%
Schedule AL-TOU – Transmission	0.8%

c. The proportion of costs recovered through volumetric rates for Schedules AD, AL-TOU and AY-TOU shall be as follows:

Secondary	100%
Primary	60%
Secondary Substation	50%
Primary Substation	40%
Transmission	40%

F. Other Rate Design

1. Schedule PA winter rates shall remain at existing levels, with all proposed changes applied to summer rates only.

2. For Street Lighting, the Distribution Demand & Customer Cost per kW per Year value in SDG&E's original proposal will be replaced by the average of SDG&E's estimate and CAL-SLA's estimate (as indicated in SDG&E's and CAL-SLA's workpapers).

II. CRITICAL PEAK PRICING

1) Beginning January 1, 2008, for a no later than April 1, 2008 implementation date, SDG&E's Default Critical Peak Pricing (CPP) proposal shall be adopted except as modified herein.

2) Beginning as soon as Default CPP is implemented for existing Customers, or on or before the day future new Customers commence service, and for the following 45 days, any Customer may immediately opt out to the OAT. The 45 days shall only begin after SDG&E has sent notice to the Customer regarding (1) the implementation of Default CPP, (2) the right of the customer to opt out of CPP and (3) the procedure the Customer must follow to opt out of CPP. After this 45 day period, Customers may opt out in accord with the provisions in Section II.5, *below*. No Customer that opts out in this initial period shall, if the Customer subsequently opts for service under the CPP rate, be allowed to participate in Bill Protection. This restriction on subsequent Bill Protection coverage does not preclude such Customers from participating in Bill Protection if Bill Protection is later adopted by the Commission as a component of a mandatory Critical Peak Pricing tariff.

3) Customers shall be entitled to reserve an uncapped amount of capacity pursuant to the Capacity Reservation Charge parameters.

4) Every two California Independent System Operator (CAISO) canceled alerts/"false alarms" shall count as one event toward the CPP annual event cap.

5) Customers not opting out of Default CPP shall be covered by Bill Protection for the first 12 months of Default CPP service. After the first 12 months on Default CPP with Bill Protection, Customers shall have up to 45 days to provide written notice to opt out of Default CPP. The 45 days shall begin after SDG&E has sent notice to the Customer regarding: a) the date the Customer's Bill Protection terminated; b) the Customer's right to opt out to an alternative rate schedule; c) the Customer's Bill Protection comparison data for the first year of Bill Protection, and d) the next opt-out anniversary dates when Customers will be allowed to opt-out of Default CPP.

   Customers will be provided the opportunity to designate a specific individual or department to receive such notice. SDG&E shall ensure that the above described notice is sent to the designated Customer representative. If no Customer representative was designated, SDG&E shall send this notice to the billing address of record.

   Provided SDG&E receives a Customer's written notice to opt-out of Default CPP at least 15 days prior to the Customer's next regularly scheduled meter reading date, SDG&E shall place the Customer on the alternative rate beginning on the Customer's next scheduled meter reading date.

Customers electing to opt out after 24 months or more on Default CPP must do so by providing prior written notice to SDG&E at least 15 days prior to their anniversary date. The anniversary date shall be included in the Customer's on-line account information and Customer records accessible by SDG&E Customer Service Representatives. These Customer Service staff shall be trained to know and explain to callers the importance of the anniversary date in the opt-out process.

6) If the Commission approves Bill Protection for Southern California Edison Company (SCE) and Pacific Gas and Electric Company (PG&E) Customers for 2009, SDG&E shall seek Commission approval to extend Bill Protection through 2009.

7) CPP imbalances shall be contained within the Commercial and Industrial (C&I) Customer class. Resulting over or under collections shall be allocated to only the following C&I rate components on an equal percentage basis:

    a. For non-CPP C&I tariffs the allocation will be limited to summer on-peak and semi-peak energy rates and summer and winter on-peak demand charges.

    b. For Default CPP tariffs the allocation will be limited to the CPP period, summer on-peak and semi-peak energy rates and capacity reservation charges.

8) SDG&E shall analyze the impact of splitting Commercial and Industrial (C&I) Customers into 3 classes, specifically 20kw to 200kw, 200kw to 500kw, and over 500kw (Class Split Study). SDG&E shall complete the Class Split Study by August 1, 2008, and upon completion of the study shall immediately convene a meeting to review the results of the study with the Customers.

9) No later than November 15, 2008, SDG&E shall file an application that: a) proposes at least one additional split of C&I Customer classes; b) includes the Class Split Study as an attachment or exhibit; c) includes, if indicated per Section 5 of this Settlement, an extension of Bill Protection for 2009; and d) incorporates all subsequently ordered Commission changes to SDG&E's CPP tariffs.

    The Parties specifically acknowledge that a November 15, 2008 filing for changes to 2009 rates may result in a Commission decision that provides for little or no Customer education prior to implementation of the revised rates, and hereby waive their rights to argue, advocate or suggest that the shortened or eliminated education period is detrimental to Customers.

III. PEAK TIME REBATE (PTR)

1. A two level Peak Time Rebate (PTR) incentive whereby a higher level payment will be provided to customers who reduce electric usage below an established customer reference level (CRL) with enabling demand response technology and lower level payment to customers without such technology.

2. Enabling demand response technology is defined to be such technology which can be initiated via a signal from the utility that will reduce electric energy end-use for specific electric equipment or appliances (e.g., programmable communicating thermostats (PCTs), AC cycling, pool pump cycling, etc.)

3. The PTR incentive payment to residential and small commercial customers is designed on a cents per kWh basis that assumes 9 event days and an on-peak period from 11 AM to 6 PM. As agreed to in this proceeding, the value of avoided generation capacity of $67 per kW-year translates to an effective incentive of approximately 98 cents per kWh for the PTR incentive payment.

4. A weighted average rate of 80 cents per kWh will be used as the basis to compute the higher PTR technology incentive payment (PTR-T) and the PTR payment without technology (PTR-NT). The reduction from 98 cents per kWh (equivalent of the $67 per kW-year value of avoided generation capacity) to 80 cents per kWh is intended to reduce the structural benefiters' incentive payout. The higher PTR-T is provided as an incentive for residential customers to purchase and install demand response enabling technologies. The PTR-T is 125 cents per kWh and the PTR-NT is 75 cents per kWh.

5. For weekday PTR events, the residential CRL will be computed as the average of 11 AM to 6 PM usage for the highest three out of past five eligible days. For a weekday event, the eligible days are the five previous weekdays, excluding PTR events, air conditioning saver or other demand response program event days and holidays. For weekend and holiday PTR events, the CRL is the highest one out of past three eligible weekend and holiday days. The event period for a weekend event is assumed to be 11 AM to 6 PM. The PTR credit will be applied to the residential customer's current billed rate.

6. For small commercial customers (<20 kW), the CRL will be the average 11 AM to 6 PM usage during the highest three out of the past ten eligible weekdays. Eligible weekdays exclude PTR event days, other demand response program event days, and holidays. For weekend and holiday event days, the CRL is the highest one out of the past three eligible weekend and holiday days. The PTR credit will be applied to the small commercial customer's current billed rate.

7. All PTR customer incentive payments are paid in each billing cycle based on the customer's sum total event day CRLs and total event period reductions over the entire bill cycle.

8. PTR incentive payment costs attributed to PTR will be recovered through the specific residential class and small commercial class that received such incentive payments, respectively, through the Energy Resource Recovery Account (ERRA).

9. All PTR administration, management, customer communications and education expenses will be recovered via the cost allocation factors as indicated by the outcome of the general cost allocation and rate design adopted in this proceeding.

10. Measurement and evaluation (M&E) of PTR demand response impacts and benefits will, at a minimum, adhere to the M&E protocols, objectives, principles and methods established in the forthcoming California Public Utilities Commission (CPUC) decision regarding the Load Impact Protocols that are being developed in Phase 1 of the Demand Response OIR 07-01-041. A ruling in that proceeding is expected by early 2008.

11. SDG&E will establish a PTR evaluation sub-committee that will be comprised of representatives from the utilities (SDG&E, Southern California Edison (SCE) and Pacific Gas & Electric PG&E)), the California Energy Commission (CEC), CPUC's Energy Division (ED) and DRA and other interested parties. This sub-committee will operate under Demand Response Measurement Evaluation Committee (DRMEC) that has been established since 2004. The DRMEC is a well established collaborative group and has been led jointly by the CEC and ED. The DRMEC is currently responsible for conducting the M&E for the three California investor-owned utilities (IOUs) commercial and industrial (C&I) demand response programs and rates.

12. The PTR evaluation sub-committee will meet prior to the implementation of SDG&E's PTR program to develop a comprehensive evaluation plan that explicitly defines the M&E objectives. The evaluation plan will follow the adopted Load Impact protocols and will also be submitted to the DRMEC for review. SDG&E will assume the lead role in the PTR evaluation sub-committee and be responsible for submitting the request for proposal (RFP) and the selection of the contractor or contractors that will conduct the M&E work. The PTR evaluation sub-committee will continue to meet periodically to review project status and to ensure that the evaluations goals and timelines are being met. Presentation of key milestones can be made formally to the DRMEC and other interested parties as needed.

13. SDG&E intends to file its PTR implementation plan, program description, and request for M&E funding in its next Demand Response program cycle filing (2009-2011). This filing will include measurement plans for demand response impacts for all dynamic rates agreed to in this settlement. This filing is expected to be June 1, 2008, per D.06-03-024, p. 21.

IV. DISTRIBUTED GENERATION-RENEWABLE (DG-R) TARIFF

1. SDG&E shall offer a new, voluntary tariff known as Distributed Generation-Renewable (Schedule DG-R).

2. Customers who qualify for Schedule DG-R may opt to use Schedule DG-R or their otherwise applicable rate as the basis for shadow billing under the CPP bill protection proposal.

3. Schedule DG-R shall be available to Customers with loads 500kW and below, who own operational, distributed generation,[2] and the capacity of that operational, distributed generation is 10% or greater of their peak annual load.

4. Schedule DG-R commodity costs shall be charged on a volumetric basis; no commodity demand charges shall apply.

5. Schedule DG-R will be designed without distribution time variant on-peak demand charges; all other distribution non-coincident demand charges imposed under Schedule DG-R shall be subject to litigation.

6. Schedule DG-R will be designed with a non-time variant distribution kWh-based charge.

7. Cost shifts related to Schedule DG-R commodity demand charge exemptions shall be retained in total C&I commodity charges.

8. Cost shifts related to Schedule DG-R distribution demand charge exemptions shall be retained in total C&I distribution charges.

[2] Solar, fuel cells, and other renewable distributed generation as defined in the statewide Self Generation Incentive Program (SGIP) standards.

ATTACHMENT A

LIST OF ANALYSIS AND STUDIES TO BE PEFORMED AND PRESENTEND IN SDG&E'S NEXT RATE DESIGN WINDOW OR GRC PHASE 2 PROCEEDING OCCURRING AFTER NOVEMBER 15, 2008

1) Determine SDG&E's new business distribution costs by customer class, and by customer payment versus utility investment. Use this to investigate the inclusion of the utility investment in new business as a customer marginal cost rather than as a distribution cost, as proposed by PG&E in its recent rate case,

2) Determine O&M of existing underground distribution by customer class, and compare this with O&M for overhead

3) Determine expected investment in replacement costs of existing underground distribution, and the customer classes served by this distribution.

4) A study of the costs of transformers and service connections that should be used in the marginal customer cost calculation for the street light class.

5) A study with supporting testimony and workpapers regarding appropriate levels of customer accounts and services O&M and TSM O&M, both in total and by customer class, since previous studies have not been conducted since 1996.

6) An analysis, with affirmative testimony supporting the appropriate level of demand distribution billing determinants by class and the method of calculating those billing determinants for (1) substations; (2) feeders and (3) new business (if included in demand, recognizing that Farm Bureau also wants to analyze it as part of the customer hookup). Without prescribing the specifics of the study, the discussion at pages 10-11 and Attachment A of the Barkovich/Yap rebuttal testimony, PG&E's use of Peak Capacity Allocation Factors (PCAF), and the actual timing of substation demands should be considered. SDG&E should develop data to provide ten years of historical data for distribution and customer-related investment.

7) SDG&E will:

A. perform an 8760-hour analysis of marginal energy costs.
B. maintain data as to the annual capacity factors of combustion turbines that it dispatches.
C. perform a study of the shape of its MECs and not rely on PX data from 1998-2000.
D. develop a production cost model and produce data on hourly incremental costs to serve its customers as the basis for developing marginal energy costs. This

analysis should consider whether incremental service is from units dispatched by SDG&E or spot purchases. If possible, the modeling results should not be withheld from parties in its next GRC on the grounds of confidentiality.[1] Once the ISO's day-ahead market is operational and there are sufficient data to determine the extent of actual rather than hypothetical utility trading in this market, SDG&E should incorporate the use of day-ahead market prices as potentially appropriate to provide a cost for those hours where these purchases are actually at the margin.

E. provide LOLP/LOLE data as part of its showing in its next Phase 2 proceeding.

F. collect and compile coincident peak demand data for all classes and schedules before its next Phase 2 proceeding, properly distinguishing between bundled and DA customers. We note that this should be easier with the phase-in of AMI implementation.

G. in its next Phase 2 proceeding, show an allocation of revenues directly to rate schedule.

[1] The data should be presented on a sufficiently disaggregated basis such that the results are meaningful for MEC analysis. Discussions should be conducted with parties before SDG&E files its next Phase 2 proceeding to work out a level of aggregation that would avoid a confidentiality battle but provide meaningful data.

ATTACHMENT B

San Diego Gas & Electric Company - Electric Department
Summary of Electric Revenue Change by Major Customer Class
GRC Phase 2 (A.07-01-047) Settlement Allocation
($Millions)

		Total Revenues		Change		
Line No.	**Customer Class**	**Present**	**Proposed**	**$**	**%**	**Line No.**
1	Residential	$1,224.329	$1,321.914	$97.585	7.97%	1
2	Small Commercial	$343.015	$354.537	$11.522	3.36%	2
3	Med & Large C&I	$1,152.413	$1,196.254	$43.840	3.80%	3
4	Agicultural	$13.703	$14.102	$0.399	2.91%	4
5	Lighting	$16.806	$16.806	$0.000	0.00%	5
6	System	$2,750.266	$2,903.613	$153.346	5.58%	6

Notes:

Present revenues based on electric rates effective January 1, 2007 (excluding FTA revenues).
Proposed revenue based on increased proposed in GRC Ph1 (A.06-12-009) (excluding FTA revenues).

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REBUTTAL TESTIMONY

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SEPTEMBER 24, 2007

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REBUTTAL TESTIMONY
OF
EDWARD FONG

I. PURPOSE AND SUMMARY

The purpose of my rebuttal testimony is to respond to prepared direct testimony filed by the City of San Diego (City) in San Diego Gas & Electric Company's (SDG&E) General Rate Case (GRC) Phase 2 rate design and cost allocation application (A.) 07-01-047. Specifically, my rebuttal testimony will address the following issues raised by the City's witnesses Mr. Tom Blair and Mr. William A. Monsen:

- Demand Rates and the Energy Action Plan (EAP) Loading Order;
- Critical Peak Pricing (CPP) Rate;
- Inclusion of October as a Summer Month for Commercial and Industrial (C&I) Customers; and
- AS-TOU Rate for Small Commercial Customers.

For the reasons stated in this testimony the California Public Utilities Commission (Commission) should disregard the arguments the City gave in opposition to SDG&E's demand charges, default CPP proposal and inclusion of October as a summer month for C&I customers, and adopt the proposals agreed to by the joint settling parties in this case. Regarding the City's opposition to the proposed AS-TOU rate schedule for small commercial customers, this is no longer an issue in this case since SDG&E withdrew its AS-TOU rate proposal per the Settlement Agreement.

II. DEMAND RATES AND THE ENERGY ACTION PLAN (EAP) LOADING ORDER

The City of San Diego criticizes SDG&E's existing distribution and proposed generation demand charges on the basis that they violate the EAP's loading order which sets forth a higher priority for energy efficiency and environmentally friendly generation to meet future load growth.[1]

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[1] "Testimony of Tom Blair on behalf of the City of San Diego Concerning The Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design", pp. 3-4; "Testimony of William A. Monsen on behalf of The City of San Diego Concerning The Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design", pp. 7, 13, 15, and 23.

The joint settling parties rate design proposal, in part, promotes cost based price signals to customers for demand and energy components and is consistent with cost causation principles and transparency in pricing that are also important elements of the EAP. To the extent that energy efficiency and self generation do not provide sufficient demand savings to warrant their use by customers does not mean that the Settlement Agreements rate design is purposefully anti-renewable energy or anti-energy efficiency. The Settlement Agreement may not provide as large a subsidy as desired by the City for solar technology. SDG&E believes any additional subsidies that the Commission deems necessary for distributed generation-renewables should be explicitly identified in a non-bypassable charges, not buried in distribution rate design.

III. CRITICAL PEAK PRICING (CPP) RATE

A. The City's witness Mr. Monsen mischaracterizes the purpose of SDG&E's proposed CPP rate and provides little factual evidence to support his statements.

Witness Mr. Monsen states the following:

> "While CPP rates, in general, would encourage customers to reduce energy use during CPP events (and/or move load to off-peak periods), the CPP program may not lead to sustained changes in energy use because, for most of the year, SDG&E has proposed relatively flat energy rates and high demand charges. In other words, it appears that SDG&E will be sending conflicting price signals to customers, with the CPP program having high energy rates in the on-peak period, but energy rates for the remainder of the year being relatively low by comparison."

> "At present, the City believes that SDG&E's current rate structure is incompatible with the CPP program. The City would be more willing to endorse the program if SDG&E's rate structure encouraged conservation, energy efficiency, distributed generation and demand response."[2]

Mr. Monsen is correct on one point. SDG&E's proposed CPP rate per joint settling parties is designed to be exactly as intended. That is, the CPP rate has been designed to provide an appropriate economic incentive, through a much higher commodity energy price during the

[2] IBID, p. 30, lines 11-17 and 20-23.

CPP event period, that encourages customers to reduce demand during periods of extremely high loads on the electric system. Demand response is the reduction of energy usage during those exceptional on-peak periods of CPP event days where energy reduction is most needed.

Depending on the specific customer load characteristics (the type of business activity), customers that decrease their usage may choose to shift some of the foregone usage to non-peak hours. Regardless of a shift in usage, the goal of demand response is achieved, i.e., reduce usage when needed. Demand response should be viewed as a compliment to energy efficiency. Energy efficiency reduces total usage, regardless of the time of day, for the end-use appliance or equipment during times when the appliance is in use. Demand response is synonymous with reductions in usage due to dynamic price signals targeted to specific times when energy use reduction is critical. Energy rates for the non-CPP and CPP hours are set on a cost basis. A known industry fact is that the Top 100 usage hours of the year (out of a total 8,760 annual hours) account for a much more significant portion of the incremental costs than the next 100 hours. Therefore, a high CPP price is warranted and a flatter non-CPP rate for the non-CPP hours seems reasonable in light of the settling parties' agreement. This inherent price differential in the CPP rate structure provides strong incentive for customers to reduce demand during a CPP event, which of course is exactly the demand response CPP rates are attempting to achieve.

SDG&E witness Mr. Bialek describes in his rebuttal testimony why demand during the non-CPP hours causes an increase in distribution related costs. The joint settling parties' proposed CPP rate is not designed exclusively to encourage shifting of demand during the CPP event period to non-CPP hours. Moreover, if the CPP rate were designed with that as a goal, then the conservation goal would be completely negated.

The City's statement that "…the CPP program may not lead to sustained changes in energy use because, for most of the year, SDG&E has proposed relatively flat energy rates and high demand charges"[3] is nonsensical. A sufficiently high CPP price will encourage customers to install demand response enabling technology to reduce usage during the selective critical peak event hours. Installation of enabling technology, such as smart thermostats and energy management systems, are changes that result in sustained demand response capabilities.

The City then attempts to argue that high non-coincident demand (NCD) charges will discourage shifting of load from the CPP hours to non-CPP hours. SDG&E's NCD demand charge is based on a customer's maximum monthly demand. Assuming that CPP events

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[3] IBID, p. 30, lines 12-14.

occurred every weekday and Saturday during the month and the customer shifted load to non-CPP event hours, the practical result would be that the NCD simply shifts, at no greater level, to non-CPP events rather than during CPP events.

Finally, the City is attempting to avoid paying for costs that it causes SDG&E to incur on its electric distribution system (demand charges) by attempting to hide behind the argument that CPP rates cannot accomplish all of the worthy goals of achieving "…conservation, energy efficiency, distributed generation and demand response.[4] While the stated goals are indeed worthy, a variety of programs and incentives, such as the multitude of statewide and local energy efficiency (EE) programs and incentives offered for the installation of distributed generation (DG), have been specifically designed and implemented to achieve those goals. As stated above, the proposed CPP rate is a compliment to EE and DG efforts with its primary objective being the achievement of demand response.

B. The City proposal to exclude Saturday CPP days should not be adopted

The City's witness Mr. Monsen claims that the inclusion of Saturday CPP days would be administratively burdensome to customers.[5] The City does not explain how the inclusion of Saturday CPP events will cause problems for customers. Per the Settlement Principles either supported or not opposed by 10 of the 12 active parties in this proceeding (see Rebuttal Testimony of SDG&E witness Steve Rahon), all customers have the ability to opt out of CPP at no cost, or, in the alternative, if a customer desires to "try out" CPP, the customer will receive Bill Protection for at least 2008. Under these circumstances, the City's claim that Saturday CPP events would be administratively burdensome to customers is nothing more than unfounded complaining and certainly is not any more or less burdensome for facilities of the settling parties.

C. The City offers no evidence that CPP rates are appropriate for only those customers with peak demand greater than 200 kW

If the Commission adopts a CPP program in this proceeding, the City proposes:

> "…that the program should be applicable only to those customers with peak demands greater than 200 kW. The City believes that the program is

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[4] IBID, p. 30, lines 22-23.

[5] IBID, p. 31, lines 14-16.

too complex for customers less than 200 kW. Moreover, these customers are less likely to have the flexibility to modify usage."[6]

The Commission should not adopt this modification to the CPP rate proposed by the joint settling parties since the City has offered no evidence that price elasticities are statistically different between 20-200 kW customers versus greater than 200 kW customers. The City states that, as an example, libraries have less flexibility to modify usage than other facilities.[7] In actuality libraries are no different from office buildings, shopping malls, etc. These other facilities will attempt to respond to CPP rates by dimming or turning off lights, raising the thermostat setting for AC and reducing unnecessary equipment usage during the few CPP hours (designed for 63 hours per year out of a total 8,760 hours). Contrary to what the City implies, the City's facilities are not dissimilar to the facilities operated by joint parties to the Settlement Agreement.

D. Default CPP rates are necessary for demand response

Unless the Commission adopts the City's recommended rate design changes, the City only supports voluntary CPP rates.[8] The City's opposition to the proposed default CPP rate and support for only voluntary CPP rates is contrary to Commission direction that broad based dynamic rates are necessary to achieve demand response. The default CPP rate proposed by the joint settling parties is consistent with Commission direction and the dynamic rate structures contained in the Demand Response Research Center (DRRC) draft report[9], and enable demand response benefits from the investment in advanced metering infrastructure (AMI).

As stated in Commissioner Chong's August 22, 2007 Assigned Commissioner Ruling (ACR) in A.06-03-005, the Commission will review the consistency of the dynamic rates adopted in this proceeding with the dynamic pricing policy adopted in Pacific Gas & Electric (PG&E) proceeding addressing dynamic pricing issues[10] in future SDG&E rate design proceedings. The joint settling parties believe that the default CPP rate defined in the Settlement

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6 IBID, p. 31, lines 7-10.

7 IBID, p. 31, lines 10-13.

8 IBID, p. 30, line 23 through p. 31, line 3.

9 DRAFT report, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators", Ahmad Faruqui and Ryan Hledik of The Brattle Group and Bernie Neenan of Utilipoint, prepared for the Demand Response Research Center, August 7, 2007.

10 Commissioner Chong August 22, 2007 ACR in A.06-03-005, p. 11.

Agreement is consistent with the direction of the Commission, that is, broad based dynamic rates for all customers. For this reason the Commission should reject the City's recommendation to keep the status quo by maintaining voluntary CPP rates and adopt the default CPP rate proposed by the joint settling parties.

IV. INCLUSION OF OCTOBER AS A SUMMER MONTH FOR COMMERCIAL AND INDUSTRIAL (C&I) CUSTOMERS

Regarding the proposal to include October as a summer month for C&I customers, the City's witness Mr. Monsen argues that SDG&E's proposal should be delayed until after AMI is installed and better information is obtained.[11] The City is incorrect in this assumption. SDG&E's proposal for summer and time of use (TOU) period changes is based on the analysis of C&I customer load research data developed using a statistically valid sample for the customer class. While AMI will provide additional information, it is highly unlikely that the general conclusions of the analysis would change significantly. Therefore, given the current analysis and timing for implementation, the Commission should adopt the proposal to include October as a summer month for C&I customers.

V. AS-TOU RATE FOR SMALL COMMERCIAL CUSTOMERS

Per the Settlement Agreement, SDG&E withdraws the proposed AS-TOU rate for small commercial customers (< 20 kW). Therefore, any objection by the City to the AS-TOU rate proposed for small commercial customers is a moot issue.

This concludes my rebuttal testimony.

[11] "Testimony of William A. Monsen on behalf of The City of San Diego Concerning The Application of San Diego Gas & Electric Company for Authority to Update Marginal Costs, Cost Allocation, and Electric Rate Design", p. 37, lines 4-18 and 21-26.

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

Application No. 07-01-047
Exhibit No.: (SDG&E-______)

REBUTTAL TESTIMONY

OF JOSEPH S. VELASQUEZ

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

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PREPARED REBUTTAL TESTIMONY
OF
JOSEPH S. VELASQUEZ

I. INTRODUCTION

My rebuttal testimony addresses:

- How SDG&E's proposed Schedule DG-R benefits solar customers while mitigating costs shits to other customers;
- Why the limiting Schedule DG-R to customers below 500 kW is appropriate;
- Refuting Fuel Cell Energy's Claim regarding System Disturbances outside the control of DG Customers;
- City of San Diego's concerns regarding conversion from SIC to NAICS; and
- City of San Diego's concerns regarding their bill presentation.

II. THE PROPOSED DG-R TARIFF IS A REASONABLE COMPROMISE BETWEEN PROVIDING BENEFITS TO SOLAR CUSTOMERS AND MITIGATING COST SHIFTS TO OTHER CUSTOMERS

In the rebuttal testimony of SDG&E Witness David Borden, SDG&E describes the bases for the demand components of its rate proposals and how these components are necessary to prevent cross-subsidies between customers and ensure customers pay the fair share for utility service. However in response to concerns of various solar parties[1] and the City of San Diego, SDG&E agreed on a compromise rate proposal, referred to as Schedule DG-R. Schedule DG-R will be available to all Commercial and Industrial customers with Solar Photovoltaic (PV), Fuel Cell Applications and Renewable Distributed Generation with demand up to 500 kW. Some of the key benefits of Schedule DG-R for these customers is that no commodity demand charges and no distribution maximum peak period demand charges apply (instead replacing them with an all energy component). As SDG&E witness Borden states, Schedule DG-R provides a discount to DG-R qualified customers paid by other customers.

Although it may not provide <u>everything</u> the solar parties want, Schedule DG-R goes a long way of providing benefits to these customers while maintaining costs to other customers reasonable. To illustrate the benefits, I would like to use the same illustrative example used by SDG&E Witness Borden in his discussion of demand and energy rate design (Figure -1).

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[1] Primarily Vote Solar and Solar Alliance.

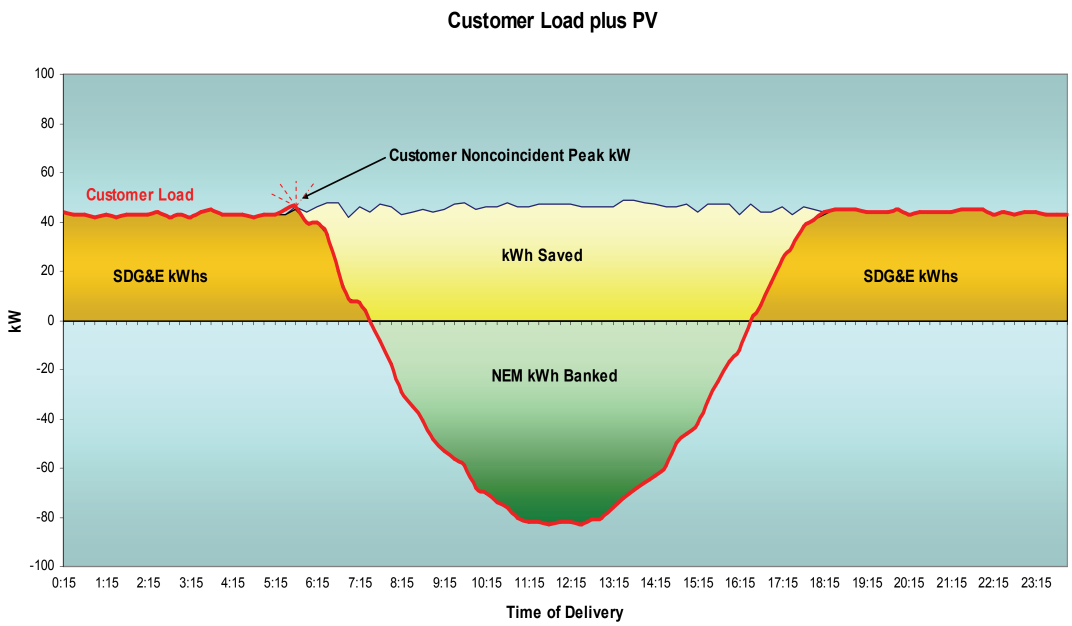

Figure - 1

In this example a customer with PV generates approximately the same number of kWh that they use on a daily basis. In order to keep the example simple we will assume this is replicated every day. The savings opportunities provided to customers under Schedule DG-R are:

- The yellow portion of the graph represents all the energy charges or kWh the customer avoids purchasing from the utility. Under Schedule DG-R these avoided costs represents all electric commodity costs (i.e., because commodity demand charges do not apply) and distribution charges collected through an energy charge (i.e., because time variant demand charges do not apply.)
- The green portion of the graph represents the net energy metering (NEM) credit accrued that day and valued at the energy charges applicable during that period. This credit can be used to offset all other energy charges when the customer was taking services from SDG&E (the mustard portion of the graph).
- It is also important to note that the energy charges during the on-peak period are valued higher than the energy charges during off-peak and mid-peak and therefore, in this example, the on-peak NEM credit would probably exceed the energy charges during the off-peak.

However, these benefits are not enough for the solar parties and the City of San Diego who are also seeking to replace the noncoincident demand charges with an energy charge. As this example shows, such a change would allow this customer to completely avoid electric distribution costs although they would be depending on the distribution system for a substantial amount of the time. If this were allowed to happen, other customers would bear the distribution costs to serve this customer.

III. LIMITING THE DG-R SCHEDULE TO CUSTOMERS BELOW 500 KW CAPTURES THE MAJORITY OF SOLAR CUSTOMERS WHILE MITIGATING THE COSTS TO OTHER CUSTOMERS

In establishing the 500 kW limit to the DG-R Schedule, SDG&E seeks to capture a large number of qualifying solar customers and mitigate costs to other customers. The DG-R schedule only requires that customers have 10% of their load served by solar; however the benefits and the discounts of the rate are applied to the entire load served on the account. Therefore a 500 kW customer would only need to install a 50 kW solar unit to qualify for the rate but the discount would also apply to the other 450 kW of load that is served by traditional utility service. Based on its research of current customers the 500 kW limit captures 80 % of the current number of commercial and industrial customers greater than 20 kW with PV.

Although some customers with fuel cells may be larger than 500 kW, we believe that these larger customers with fuel cells should operate in a way that would allow them to avoid the demand charges excluded from Schedule DG-R. Unlike solar, fuel cells do not depend on weather or the time of day, hours of sun or solar intensity. SDG&E does not believe it is appropriate to extend the discounts inherent in Schedule DG-R and paid by other customers to fuel cell customers greater than 500 kW that can not operate their fuel cells wisely or reliably.

IV. FUELCELL ENERGY'S CLAIMS OF SDG&E'S OUTAGES LEADING TO OUTAGES IS UNSUBSTANTIATED

FuelCell Energy claims that transitory outages outside the control of the DG customer are the result of disturbances on SDG&E's system. SDG&E has investigated FuelCell's claims regarding system disturbances and has found no support indicating that such disturbances are caused by SDG&E. SDG&E has requested that FuelCell Energy provide support for its claim that such outages are a result of disturbances on SDG&E's side of the meter and FuelCell Energy appears to lack any support for its claim. SDG&E believes that it is being unfairly blamed for potential disturbances caused on the customer's side of the meter, potentially faulty distributed generation equipment that may not operate reliably under the customer's existing electric circuitry, or the failure to install additional power conditioning or power quality equipment. If so, all of these are clearly under the control of the customer, fuel cell manufacturer vendor and their contractor. SDG&E asked FuelCell the following in a data response:

> **Question 2:** On Page 7 of Mr. McClary's testimony, he states that "A recent analysis of savings to a potential customer in SDG&E's service area found…lost savings, due primarily to system disturbances outside the control of the customer or DG provider, added nearly 15% to the customer's overall electricity cost." Additionally you stated that "In many cases the event triggering ratcheted demand charges is a system disturbance…"
>
> Please fully define and describe what is meant by "system disturbances."
>
> **Response:**
>
> A "system disturbance" as used in this instance refers to an event such as a voltage deviation or frequency **deviation** that occurs on the system, not at the customer site, that causes the on-site fuel cell generation to trip off-line.
>
> Please provide all data including but not limited to dates, time of occurrence, nature of disturbance (e.g., voltage excursion) and duration of each occurrence?
>
> **Response:**
>
> FuelCell Energy **does** not have a detailed record of this information, but is seeking specific information from its customers. We will supplement this response to the extent additional information becomes available. We believe that SDG&E itself should have records of system disturbances that would provide the requested information.
>
> SDG&E has investigated such disturbances for a client of FuelCell and although the issue is still under investigation, SDG&E has found indications that if such disturbances occurred they may have resulted from the customer's operations and/or equipment.

V. CONVERSION FROM SIC TO NAICS

The City of San Diego recommends that the Commission reject SDG&E's proposal to switch from the Standard Industrial Classification ("SIC") to the North American Industry

Classification System ("NAICS") for customer classification purposes. The City is concerned that some customer accounts currently on the Schedule PA-T-1 and Schedule PA may lose their eligibility as a result of the switch. The City claims that SDG&E has presented no compelling reason for this switch. (City of San Diego, Testimony of William A. Monsen, pp. 38 - 39)

For various statistical reporting reasons, SDG&E historically has flagged its customer billing accounts with SIC codes. In response to the widespread adoption of the NAICS codes and to better align its customer classification coding system with agencies like the California Energy Commission, SDG&E recently began process of replacing SIC codes with NAICS codes. After reviewing its current and effective tariffs, SDG&E discovered that its rate schedules PA and PA-T-1 contained references to the outdated SIC codes. As a result, SDG&E proposed to replace the references to SIC codes with the more widely used NAICS codes.

In response to SDG&E's proposal, the City of San Diego seems to be concerned that some customer accounts currently on the Schedule PA-T-1 and Schedule PA may no longer be eligible for service under these rate schedules as a result of the switch. The City goes on to claim that SDG&E has presented no compelling reason for this switch.

This innocuous replacement of SIC codes with NAICS codes to be consistent does not change the applicability requirements set forth in either Schedule PA or Schedule PA-T-1. If a customer is currently eligible to receive service under either of these schedules, this eligibility will no be jeopardized the simple change from SIC to NAICS codes. Additionally, new customers that would be eligible for service under either schedule with the existing references to SIC codes will be eligible under the schedules after the replacement with NAICS codes. Moreover, given the tremendous interaction and informational exchanges between SDG&E and government agencies such as the CEC, SDG&E has provided a solid basis for making the change. For the reasons stated above, the Commission should reject the City's assertions and adopt SDG&E's proposal.

VI. TRANSPARENCY IN SDG&E'S BILLING SYSTEM

The City of San Diego indicates that the lack of transparency in SDG&E's billing system for solar customers is a reason that they might halt development of solar projects. (City of San Diego, Testimony of Tom Blair, pp. 15 – 16) The City indicates that the lack of transparency relates to the following: 1) SDG&E does not provide total energy usage and total solar energy produced on the bill but instead provides only net energy usage or net energy generated; 2)

SDG&E does not set forth the rates on the bill that are used to calculate the net metering credits that are carried forward to the next month; and, 3) SDG&E does not provide net metering credits on a monthly basis but instead provides them on an annual basis. (City of San Diego, Testimony of Tom Blair, pp. 15 – 16)

Providing information with regard to net energy metering on a customer's bill is simply not practical given the limited amount of space available on customer billing statements. While SDG&E must strike a balance between useful information and too much information, in terms of what is provided on a customer's bill, detailed net energy metering information is included on a separate document inserted in the billing envelope each month for larger non-residential accounts. Additional information can be provided through hard copy (for a charge) or free of charge on the internet.

In response to the City's specific concerns that SDG&E does not provide total energy usage and total solar energy produced by a solar customer on the bill, SDG&E currently provides this data in the monthly billing envelope for customers with demand of 500 kW or higher because the cost of the service is included in the higher basic service fees that are charged these customers. Per the terms of SDG&E's Rule 9, Rendering and Payment of Bills, Subsection G., Purchase of Interval Meter Data by Customers Under 500 kW, the City can receive a hard copy of the monthly interval data by meter for the cost of $20 per meter, per month. Thus, the data is available to the City if they wish to subscribe to the service. For the City's accounts that are below 500 kW demand the City can access and download 15 minute interval data by account and by meter free of charge on SDG&E's web site.
(See the link: https://paladin.sdge.com/energywave/cfm/signon.cfm)

While the City indicates that this information is extremely important for auditing purposes and that it could "scour through other sources to reconcile this information" , the truth is that the City only has to log-in to its account on SDG&E's web site and match the account number that it seeks to audit. The data can be viewed for each meter associated with the account, including consumption and generation, in 15 minute intervals, if that is desired. SDG&E has employees available who are trained in the use of the internet site and who can assist the City in accessing its billing data online.

With regard to the City's claim that SDG&E does not set forth the rates on the bill that are used to calculate the net metering credits that are carried forward to the next month, SDG&E provides the total rate used to bill the customer or to credit the customer on their bill. The individual rate components that make up the total rate are also available free of charge on SDG&E's web site.

The City's concerns about the provision of monthly credits for net metering for solar customers seems to center around the current methodology used by SDG&E to display credits and charges on a customer's bill. When a customer, like the City is billed under a time-of-use (TOU) rate schedule, credits and charges are displayed separately on the bill for each TOU period. SDG&E's is currently not programmed to net the monetary values associated with these TOU periods, however a separate statement is enclosed with the monthly bill that clearly shows a running total of credits. SDG&E is currently working on the system programming that is necessary to provide the net the monetary credits and will have it fully operational sometime during the first quarter of 2008.

This concludes my rebuttal testimony.

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

Application No. 07-01-047
Exhibit No.: (SDG&E-_____)

REBUTTAL TESTIMONY

OF DAVID A. BORDEN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

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PREPARED REBUTTAL TESTIMONY

OF

DAVID A. BORDEN

I. INTRODUCTION

My rebuttal testimony, in conjunction with the Rebuttal Testimony of SDG&E witness Bialek, addresses:

1. Distribution Non-coincident Demand (NCD) issues, including the distribution NCD ratchet;
2. City of San Diego's (CSD) issues with commodity demand charges; and
3. CSD's issue with the submission of tariffs to implement Decision 2 05-08-013 and Resolution E-3992 regarding Net Energy Metering for Combined Technology Distributed Generating systems.
4. Miscellaneous arguments raised by CSD and other parties.

II. DISTRIBUTION NCD CHARGES

A. NCD Charges

SDG&E proposes to maintain the distribution NCD and the related demand ratchet in the majority of our Commercial and Industrial (C&I) rates, including in the Schedule DG-R that is proposed in the Settlement Principles as discussed in the rebuttal testimony of SDG&E witnesses Mr. Rahon and Mr. Velasquez. SDG&E's proposed C&I rate design is consistent with cost causation principles that design rates in a manner similar to how costs are incurred on the system. Rate design that reflects cost causation principles essentially attempt to minimize subsidies between customers and provide transparent price signals. For C&I customers, distribution rates are designed to recover customer service and hookup costs through basic service fees and demand charges that reflect the customer demands placed on the system during summer and winter peak periods and those that are placed non-coincident with peak periods. The cost of providing distribution service is largely fixed primarily to serve customer non-coincident demand. (SDG&E, Rebuttal testimony of Bialek, pp. 1-2)

To illustrate, if Customer A and Customer B have noncoincident demands of 100 kW and 25 kW, respectively over the same period, and both use the same amount of energy 100 kWhs, the distribution system must be sized to take into account the higher demands of Customer A despite the fact that they occur less frequently. Under SDG&E's current and proposed distribution rate design for C&I customers, poorer load factor customers like the hypothetical Customer A pay more for use of the system. For example, if total distribution costs are $1,000, then on a NCD basis the demand charge would equal about $3/kW and Customer A and B would be billed about $667 and $333, respectively. By moving to an all energy rate the charge would be $5/kWh and customer A and B would each be billed $500 despite the higher cost to serve Customer A.

With respect to Schedule DG-R, renewable distributed generation does not necessarily allow SDG&E to avoid the costs incurred to serve the customer's demands on the distribution system because renewable distributed generation may have limitations in its ability to lower a customer's demand. The costs to serve that demand does not disappear as a result of energy sent to the grid in other time periods. SDG&E must have distribution facilities in place to seamlessly and reliably serve a renewable distributed generation customer's load when their generation cannot or does not generate power to offset their load. By designing rates on cost causation principles that reflect the demand based nature of the costs of the distribution system, SDG&E treats renewable distributed generation customers and other customers in the same fair and reasonable manner that is based on cost of service. Schedule DG-R, as proposed, deviates from SDG&E's proposed cost based rates and as such is inherently a subsidy to customers with renewable generation. That is to say, cost recovery through a greater use of energy rates for demand based costs will allow renewable generation customers to avoid recovery of costs that SDG&E does not avoid and that must then be recovered from other customers. If even after applying Schedule DG-R, renewable distributed generation is still uneconomic and the Commission believes that additional subsidies are warranted, then these additional subsidies should be provided through transparent, non bypassable charges, not buried in distribution rate design.

B. Demand Ratchet

As The City of San Diego explains in the testimony of Mr. Monsen, the ratchet can cause certain customers to pay NCD charges even in months when energy usage is low or zero. (City of San Diego, Testimony of William A. Monsen, p. 19). However, this is appropriate rate design following cost causation principles because the distribution system investment is largely fixed. When a customer uses little or no energy SDG&E must still size distribution facilities to meet their demands when they are incurred. SDG&E believes that application of demand ratchets should be continued to minimize potential cross subsidization. The City indicates that one of the benefits of eliminating the demand ratchet would be encouraging conservation (City of San Diego, Testimony of William A. Monsen, pp. 19), but the aim is misplaced because SDG&E may not experience distribution cost savings from energy reductions. (SDG&E, Rebuttal Testimony of Thomas Bialek, pp. 1-2) The demand ratchet is designed to recover the cost of providing distribution service to low load factor customers, who by definition have low energy usage relative to other customers with similar demands and it has worked well when one considers that it applies to a small number of C&I accounts.

The City further argues that elimination of the demand ratchet will provide equity in treatment between residential, small commercial, and C&I customers because residential and small commercial do not currently face demand charges. (City of San Diego, Testimony of William A. Monsen, p. 20) Residential and small commercial customer rate design should not be used as basis for designing C&I rates. The lack of demand charges for residential and small commercial customers is more a function of the historically prohibitive costs of demand meters for these customers, the ability of the customers to understand more complex rates, and the resources available to them.

The City's final argument for the elimination of ratcheted distribution demand charges is that it will have minimal effect on rates. (City of San Diego, Testimony of William A. Monsen, pp. 20-21) The argument that the elimination of the demand ratchet will not harm other customers is misplaced because it relies upon the snapshot of bill impacts today from a billing analysis when the ratchet is applicable and it does not take into account cost shifting between customers within the rate schedule. If SDG&E's demand ratchet were not applied to historical billings then demand billings may decrease by less than 2% in total, but the latter is a strong indication that the ratchet is reasonably designed today and that a monthly demand level is ratcheted upwards only for those customers with the greatest variability in monthly demands and poorest load factors. However, it does not follow that eliminating the ratchet will result in the same small numbers of accounts with poor load factors and high variability in demands. What is more likely to occur is that as solar installations increase and those customers become poorer load factor customers, then the subsidy from higher load factor customers is likely to increase without the demand ratchet.

FuelCell indicates that demand ratchets do not provide appropriate price signals and are a disincentive to distributed generation and should be eliminated. (FuelCell, Testimony of Steven C McClary, pp. 5-7, 12 – 16) The demand ratchet is appropriate rate design following cost causation principles because the distribution system design and investment is largely fixed. (SDG&E, Rebuttal testimony of Can Truong, pp. 1-2) Thus, even when a customer uses little or no energy SDG&E must still size distribution facilities to meet their demands when they are incurred. SDG&E believes that application of demand ratchets should be continued to minimize potential cross subsidization.

Fuelcell recommends that if demand charges remain then they should be based on maximum monthly demand without the ratchet mechanism. (Fuelcell, Testimony of Steven C McClary, pp. 5-7, 13 – 14) Although Fuelcell indicates that maintaining demand charges without the ratchet has little impact on other customers, the analysis is not persuasive because it relies upon the snapshot of bill impacts today from a billing analysis when the ratchet is applicable. That SDG&E's demand ratchet applies to small percentage of C&I customer accounts, is a strong indication that the ratchet is reasonably designed today and is implemented only for those customers with the greatest variability in monthly demands and poorest load factors. It does not follow that eliminating the ratchet will result in the same small numbers of accounts with poor load factors and high variability in demands or that providing the subsidy to these customers is okay because many customers won't notice the size. What is more likely to occur is that as distributed generation increases and those customers become de facto poor load factor customers, then the subsidy from higher load factor customers is likely to increase without the demand ratchet. Fuelcell acknowledges the possibility of cost shifting but indicates that it could be offset over time by benefits from distributed generation. (Fuelcell, Testimony of Steven C McClary, p. 17) SDG&E believes that the Commission should set rates on a cost basis today and not encourage new subsidies that may be offset some time in the future.

FuelCell indicates that SDG&E's demand ratchets will discourage the development and deployment of new DG and have eroded savings for customers as a result of transitory outages that are outside the control of the DG and that are the result of disturbances on SDG&E's system. FuelCell also claims that these direct adverse rate impacts have resulted in the cancellation of future DG installations for some of its clients California sites. (FuelCell, Testimony of Steven C

McClary, p. 6-7) The principle of applying demand ratchets is addressed above. The specific issues related to transitory outages and disturbances is addressed in the rebuttal testimony of witness Velasquez.

III. COMMODITY DEMAND CHARGES

For the commodity rate component, SDG&E incurs capacity and energy costs related to the generation of electricity. Capacity is the resource and associated costs to meet instantaneous demand, e.g., a 500 MW power plant provides 500 MW of generation capacity to meet 500 MW of customer demand at any moment in time. Energy costs vary over time and are generally the variable costs associated with running the same 500 MW power plant for X number of hours. SDG&E currently recovers its total commodity costs through energy only rates and proposes to recover 50% of its capacity costs through monthly maximum period demand charges and the remainder of commodity costs through energy charges. SDG&E's current rates result in a subsidy from high load factor customers to low load factors and SDG&E's proposal gradually moves to eliminate that subsidy. Using the same hypothetical customers discussed in Section II, above, SDG&E must invest in generation to meet the 100 kW demand imposed by Customer A and the 25 kW demand imposed by Customer B for 1 hour. If Customer A had a load profile similar to Customer B then SDG&E could reduce its capacity investment by half. By using demand charges to recover its capacity costs, SDG&E will appropriately assign a greater share of capacity costs to customers with poorer load profiles and provide a price signal to flatten loads over time.

The City of San Diego opposes SDG&E's proposed commodity demand charge because they claim that it is based on the wrong demand determinants, sends incorrect price signals because it results in lower peak energy charges, and is inconsistent with SDG&E's testimony regarding residential rates. (City of San Diego, Testimony of William A. Monsen, p. 23 - 29)

The City argues that the demand determinants are incorrect because SDG&E uses maximum peak period instead of coincident peak period demands. SDG&E proposes that maximum monthly peak demand determinants be used because that is what is available for the vast majority of C&I customers (200 kW or less) and the maximum monthly peak period demands provide a measure of customer contribution to peak period capacity costs. SDG&E's proposed demand charges are initially based on an allocation of marginal generation capacity costs according to the class average contribution to the system peak demand. With the exception of Schedule A6-TOU, which employs demand charges coincident with system peak, SDG&E's demand charges are based on coincident peak demand but recovered through rate schedules via maximum monthly peak demands. SDG&E's proposal is gradual movement towards coincident peak commodity demand charges. As SDG&E has the capability to measure coincident peak demand for its C&I customers, through the roll-out of AMI, it will have the necessary demand determinants to recover demand charges on a coincident peak demand basis but even at that time there may still be customer acceptance issues over such rates. Rather than form a basis for rejection of SDG&E's proposal, the use of the maximum monthly demand billing units should be viewed by the Commission as gradual implementation of the commodity demand charge.

The City claims that SDG&E's commodity demand charge provides a strong disincentive to install new solar systems because the solar generation will not be able to offset all load during the peak period hours and because the commodity demand charge comes at the expense of peak period energy charges thus lowering credits. (City of San Diego, Testimony of William A. Monsen, pp. 24 - 26) SDG&E's proposed demand commodity demand charge is intended to send the cost based price signal to customers regarding capacity. If solar generation is not capable of offsetting the customer's load during peak periods, for whatever reason, then SDG&E's proposed rates charge the customer for the loads that it imposes on the system. If the City prefers a commodity rate based on coincident peak determinants then it should consider SDG&E's proposed CPP rates as an option. Under current commodity rates, without a proposed demand charge, low load factor customers receive a subsidy from higher load factor customers. SDG&E's proposal will mitigate this subsidy and provide cost based prices for solar installations. To the extent that solar is able to offset a customer's load during the peak period they receive due value by avoiding demand charges. Finally, SDG&E proposes Schedule DG-R in its rebuttal testimony that is applicable to solar and DG units that meet its eligibility requirements. Schedule DG-R does not use commodity demand charges and instead replaces SDG&E's proposed commodity demand charges with energy components.

The City claims that a 2nd effect harming solar and energy efficiency is that customers will receive a lower peak energy credit when they generate to the grid because the demand charge results in lower peak period energy charges. (City of San Diego, Testimony of William A. Monsen, pp. 26 - 27) The peak period energy charge reflects SDG&E's proposed marginal costs, so to provide additional credits would result in increased subsidies to solar customers and energy efficiency. To the extent that energy efficiency does not reduce customer demand then the appropriate credit is the commodity energy charges. SDG&E proposes Schedule DG-R in its rebuttal testimony that is applicable to solar and DG units that meet its eligibility requirements. Schedule DG-R does not use commodity demand charges and instead replaces SDG&E's proposed commodity demand charges with energy components.

The City claims that SDG&E's proposed commodity demand charge for C&I customers is inconsistent with SDG&E's proposals for residential rates. (City of San Diego, Testimony of William A. Monsen, pp. 27 - 28) This is another use of the argument that the Commission should use residential rate design as the standard for C&I rate design because the results benefit C&I customers with low load factors. Residential rates do not have demand charges on distribution or generation because historically it has been cost prohibitive to provide the metering equipment relative to the customer's total demand and energy on their bill, the desire for simplicity in residential rate design, and that fewer resources are devoted to residential customers to assist them in their understanding. On the other hand, demand charges are common for C&I customers and their use should not depend on whether the outcome sought were advanced by residential rate design.

IV. NET ENERGY METERING COMPLIANCE ISSUES

The City of San Diego argues that the Commission should require SDG&E to implement tariffs addressing net energy metering for combined technology DG systems consistent with D.05-08-013 and Resolution E-3992 immediately. (City of San Diego, Testimony of William A. Monsen, p. 40) As the City articulates, the issue relates to DG facilities at the same location that use different technologies and where not all of the DG is eligible for net metering credits. SDG&E, in a data response to the City and included as attachment WAM-4 to the City's testimony, indicated that it expects to file further revised tariffs, as recommended by the Energy Division Staff, in July 2007. The City states that as of August 9th, 2007, SDG&E has not made said filing. (City of San Diego, Testimony of William A. Monsen, pp. 39 - 40)

The issue at hand is an ongoing compliance matter. On August 13, 2007, SDG&E filed Advice Letter 1777-E-B, in compliance with E-3992 and D.05-08-013, and replacing Advice Letter 1777-E-A in its entirety. On August 31, 2007, the City of San Diego filed a protest to SDG&E's Advice Letter 1777-E-B. On September 10, 2007, SDG&E filed a response to the

City's protest. The issue is before the Commission through the Advice Letter process and does not require adjudication in the instant proceeding.

V. MISCELLANEOUS CSD AND OTHER PARTY ARGUMENTS

A. Residential and Small Commercial Rate Design as the Standard for C&I Rate Design

CSD indicates that because SDG&E's residential rate design is based on all energy rates and that SDG&E is not harmed by this, then it somehow demonstrates that all energy rates will work for C&I customers. (City of San Diego, Testimony of William A. Monsen, p. 15) It is inappropriate to compare the residential and small commercial rate design with C&I rate design because: 1) energy rates for residential and small commercial customers are a function of the historically prohibitive costs of demand meters ; 2) residential customers are not typically as knowledgeable about sophisticated rate design as business customers; and 3) residential and small commercial customers typically have fewer resources devoted to evaluating their service. SDG&E continues its practice of applying distribution NCD charges to C&I customers based on cost causation principles and it is not a question of whether SDG&E can somehow make all energy rates work for C&I customers because they have done so for Residential and Small Commercial. SDG&E's policy is to promote movement towards cost based rates -- not additional subsidies. The Commission has approved more sophisticated metering in both SDG&E and PG&E 's territory and is holding a proceeding to assess SCE's advanced metering proposal. Advanced metering will provide more dynamic pricing and more accurate price signals to customers. Moving C&I rates in the direction of residential rates is going backwards and contrary to the Commission's goals of providing dynamic pricing and promoting demand response through advanced metering technology.

In the City of San Diego's response to SDG&E's data request the City indicates that it desires to be treated like residential, small commercial and agricultural customers through all energy rates:

> QUESTION: Do you believe SDG&E continues to incur costs associated with providing electric service to the City after the installation of solar?
>
> -- If not, please explain why.
>
> -- If yes, do you believe some of the costs are fixed costs?

-- If yes, do you believe the City should be responsible for paying the costs associated with providing it electric service?

-- If not, who should pay for those costs?

RESPONSE: Yes and the City believes that it should pay for the costs associated with electric service (including any fixed costs) based on net usage, similar to residential, Schedule A and Schedule PA customers.

The City agrees that SDG&E continues to incur distribution system costs even after the City's installation of solar, but the City's preference results in other customers paying for the cost recovery that was previously the responsibility of the City and for which solar may not avoid.

B. Demand and Energy Rate Design and Net Metering Credits

The City of San Diego is critical of SDG&E's demand component for distribution rate design because they claim that it does not permit them to receive the full net metering credit during periods when their customer self generation sends power to the grid. The City of San Diego claims that the distribution NCD charge discourages energy efficiency and is a disincentive to distributed generation and the installation of solar facilities. (City of San Diego, Testimony of Tom Blair, pp. 3-10; City of San Diego, Testimony of William A. Monsen, pp. 6-7)

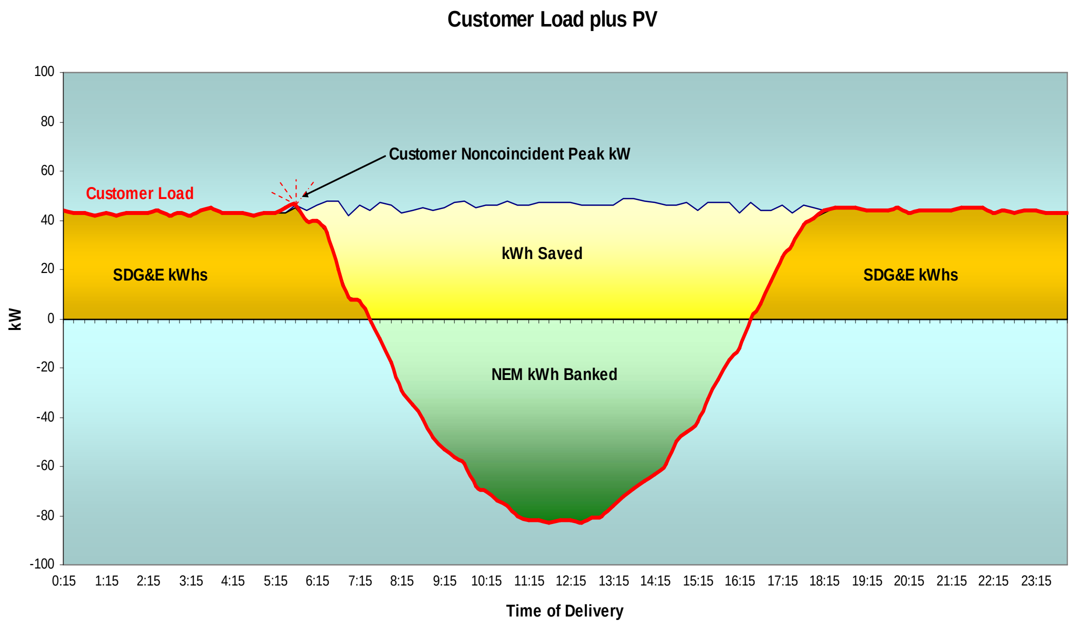
Applying net metering energy credits from generation to distribution noncoincident demand components is incorrect because the net generation to the grid does not offset distribution costs and may not be representative of the distribution demands incurred by the customer during times when solar does not generate. Moreover, SDG&E's position is in compliance with the statute, which indicates that net metering credits are applicable to kWhs not kWs. California Public Utilities Code Section 2827(h)(B) and (C) state as follows:

> (B) For all eligible customer-generators taking service under tariffs employing "time of use" rates, any net monthly consumption of electricity shall be calculated according to the terms of the contract or tariff to which the same customer would be assigned to or be eligible for if the customer was not an eligible customer-generator. When those same customer-generators are net generators during any discrete time of use period, the net kilowatthours produced

> shall be valued at the same price per kilowatthour as the electric service provider would charge for retail kilowatthour sales during that same time of use period. If the eligible customer-generator's time of use electrical meter is unable to measure the flow of electricity in two directions, paragraph (3) of subdivision (b) shall apply.
>
> (C) For all residential and small commercial customer-generators and for each billing period, the net balance of moneys owed to the electric service provider for net consumption of electricity or credits owed to the customer-generator for net generation of electricity shall be carried forward as a monetary value until the end of each 12-month period. For all commercial, industrial, and agricultural customer-generators the net balance of moneys owed shall be paid in accordance with the electric service provider's normal billing cycle, except that if the commercial, industrial, or agricultural customer-generator is a net electricity producer over a normal billing cycle, any excess kilowatthours generated during the billing cycle shall be carried over to the following billing period as a monetary value, calculated according to the procedures set forth in this section, and appear as a credit on the customer-generator's account, until the end of the annual period when paragraph (3) shall apply.

Clearly the statute refers to net metering credits applicable to net kilowatt hours produced and excess kilowatt hours generated—not demand components billed on a kilowatt basis.

Figure 3 below is for illustrative purposes and shows an example of the hourly load profile for a medium size commercial customer with solar and for one day when net usage is close to or equal to zero. Although the customer saves significant amounts through reduced energy consumption during the hours when solar produces, and is able to credit kWhs generated to the grid to offset other kWh usage, the customer's solar installation does not permit them to reduce their distribution NCD to zero. The distribution costs that SDG&E incurs to serve the customer do not go to zero despite the customer's zero energy usage that results from net metering credits. Suppose that the customer in this example has a 45 kW demand for the month and 0 kWh of usage, at the current distribution rate of $6.77/kW for secondary service under Schedule AL-TOU, the customer would be billed $305. If the Commission were to heed the complaints from the parties advocating greater subsidies for solar, then the Commission should be concerned that the customer might incur an infinite cost for power for the month in terms of the average price in $/kWh, despite the fact that the customer actually saves significantly from the installation of solar. Furthermore, the Commission should be concerned that other potential solar customers might base their decision to install solar using the same average cost per kWh and thus might also pay an infinite cost for power once they install solar. It is unclear how a customer can afford an infinite amount for power, but the truth is that net metering credits provide substantial savings for solar customers and the distribution NCD charge appropriately recovers the cost of providing service to solar customers.



C. Customer Account Examples

The City of San Diego provides billings for its Alvarado water treatment plant as an example of not receiving full credit for energy generated by its solar installation. (City of San Diego, Testimony of Tom Blair, pp. 4-5) The example presented by the City is complicated by how information is currently presented on the customer's bill, but the City's example is unconvincing because the City mismatches net energy generated to the grid with demands incurred by the customer and the City does not discuss the customer's total savings since the installation of solar. The City gives the impression that their expectations of their solar installation were such that it would result in a zero total bill and the City indicates that it expected that the solar installations to allow it to avoid the full retail rate and maintain their same pre-installation average cost per kWh. (City of San Diego, Testimony of Tom Blair, pp. 4-5)

However, such expectations would be unrealistic given the limitations of solar technology and the demands placed on the system by Alvarado, as well as a reasonable interpretation of the statute that is cited by the City concerning net energy metering credits. The City expected that the solar installation at Alvarado would allow them to avoid SDG&E's entire retail rate and SDG&E interprets this to mean that the City expected to pay zero. When SDG&E asked the City, in a data request, for all documents, workpapers, and analysis that lead the City to conclude that their electric bill from SDG&E would be zero, the City responded:

> RESPONSE: The City does not believe that under SDG&E's current tariff that its bill "would be '0'." In addition, the City notes that if it were taking service under PA, its bill under the circumstances described in its testimony (e.g., when the value of the energy delivered exceeds the value of energy used), would be zero and the City believes that this is the appropriate treatment, given State and Commission mandates to encourage solar and other renewable technologies.

For whatever reason, the City's response indicates that it does not believe that its bill would be zero. The City then goes on to indicate that if they were taking service on schedule PA that their bill would be zero under the same circumstances. However, there is nothing preventing the City from applying for service under Schedule PA. Schedule PA is for agricultural power service and if the City believes that the Alvarado water treatment plant meets the eligibility requirements for Schedule PA then they can apply for service. The City indicates that this is the appropriate treatment given State and Commission mandates to encourage solar and other renewable technologies. However, the State and the Commission have not mandated that solar and renewable technologies should be given the largest subsidy that they can discern from a review of utility tariffs. The City's response further demonstrates its apparent misunderstanding of the statute with respect to net metering energy credits that led it to believe that its bill would be zero. That is to say, if net metering energy credits were required to be applied to demand charge components of the bill, then the City would not need to seek service on other tariffs or to change existing tariffs to treat them as if they were on another tariff that does not have demand charges. The City could simply ask the Commission to order SDG&E to comply with the statute and commence applying net metering energy credits against the entire bill, including demand charge components. It is noteworthy that the City is silent in its testimony and data responses with respect to such a recommendation. Further examination of the details regarding the City's Alvarado water treatment plant example is provided below.

The City uses the Alvarado Water Treatment Facility ("Alvarado") on Schedule PA-T-1 Option D as an example of why demand charges are anti-solar. Schedule PA-T-1 is an experimental power optional time of use rate for agricultural purposes where the customer can select one of several TOU options for service. To the extent that a customer can manage their load, then Schedule PA-T-1 provides the opportunity for lower monthly bills compared to Schedule AL-TOU due to the smaller peak period and because demand charges are not applied outside the peak and semi-peak periods. The customer in this instance selected Option D, which provides for the following TOU periods:

Schedule PA-T-1 Option D	May 1 – Sept. 30 Weekdays	All Other Weekdays
On Peak	1 P.M. – 3 P.M.	5 P.M. – 8 P.M.
Semi-Peak	6 A.M. – 1 P.M. 3 P.M. – 10 P.M.	6 A.M. – 5 P.M. 8 P.M. – 10 P.M.

From a review of the time periods, Option D provides the customer with a 2 hour window during weekdays (1-3 P.M.) over which the summer peak period distribution demand charge may be applied. If customer load on the SDG&E system is avoided during this small summer peak period window (the normal window is 11 A.M. - 6 P.M. for customers of this size) then the customer is able to avoid the summer peak distribution demand charge of $5.23 per kW for primary level service (based on 1-1-2007 rates). The City indicates that the demand charge is $5.46 per kW in their testimony but the amount cited by the City includes $0.23/kW for the CTC rate component. The distribution demand charge for semi-peak on 1-1-2007 was $1.37 per kW—not the $5.30/kW indicated in the City's testimony. It appears that the City included demand charges for Transmission, CTC, and Reliability Service in its calculations, but the issue in the instant proceeding is the distribution demand charge.

Further inspection of the City's testimony shows that the billing provided is for the month of April, a winter month where the peak period demand charge window is 5-8 P.M.

The distribution demand charge applicable under Option D is a maximum peak and semi peak period demand charge— which is not the same as the distribution NCD charge that would apply if this account were on Schedule AL-TOU. Schedule PA-T-1 sets forth under Special Condition 9 that:

> 9. Demand Charge Option B through F. The Demand Charge will be based on kilowatts of maximum demand as measured each month during the On-Peak and Semi-Peak Periods. The Maximum Demand during the On-Peak and Semi-Peak Periods shall be the average kilowatt input during the fifteen-minute interval in which the consumption of electric energy is greater than in any other fifteen minute interval during the respective Periods, as indicated or recorded by instruments installed, owned and maintained by the utility.

To the extent that the customer's solar system offsets load during the peak and semi peak hours then the customer avoids the distribution demand charges. The NCD charges applicable to a customer on this rate would be for the Transmission and Reliability Service components, which are subject to FERC jurisdiction and that are otherwise outside the scope of this proceeding.

Under a favorable experimental rate, the solar generation did not sufficiently offset the customer's load and thus Alvarado could not avoid all of the distribution demand charges. The issue here might otherwise be framed as the City's unrealistic expectations regarding solar given the load at Alvarado and the statute requirements with respect to net metering credits applying to demand charges.

Rebuttal of the City's example of the Alvarado treatment plant should end above, but unfortunately the City makes the claim that because they did not use any energy during the month that the charges billed for are de facto standby rates and are thus contrary to statute that prohibits standby charges for solar installations. (City of San Diego, Testimony of Tom Blair, p. 6) Looking at the City's Table 1, it appears from their own example that the Alvarado treatment plant imposed demands on the SDG&E system during both peak and semi peak periods of 328 kW and 436 kW, respectively. The energy usage is positive during the peak period and demand is positive so the Alvarado water treatment plant used the SDG&E system during the peak period, which is contrary to the City's "de facto" standby claim. Breaking it down further, the City's table shows negative energy during the semi-peak period but positive demands. The negative energy indicates that the City was a net generator to the grid for the entire semi peak period hours but the positive demand indicates that for some portion of those hours the solar generator did not offset the customer's load and they demanded power from SDG&E's system. In their argument the City is mismatching energy generated by their solar with their demand for power from SDG&E. The bottom line is that the City did not receive a zero bill in the example presented because they imposed demands on the system and were billed accordingly.

The City discusses the Oak Park Library ("OPL") as another example where SDG&E's rate structures discourages installation of solar facilities. (City of San Diego, Testimony of Tom Blair, pp. 7-9) The OPL apparently benefited from receiving service at Schedule A rates when it should have been classified for service on Schedule AL-TOU. The OPL may have received a significant financial benefit over time only because SDG&E could not measure its demand level with the existing metering equipment. Once the account was correctly reclassified as AL-TOU, after interval meters were installed due to the OPL's installation of solar, the customer's measured demand level disqualified it from service under Schedule A. It is unclear what the City knew regarding the demand level of the OPL prior to installation of solar but apparently enough was known to install 20 kW of solar capacity. It is unfortunate for the City that the subsidy that they received when they were misclassified as a Schedule A customer cannot continue to be applied to their solar installation but SDG&E believes that the OPL account demonstrates why greater transparency in cost based rates, including the continued practice of applying distribution NCD charges, is needed instead of a rate structure that will hide subsidies through all energy charges, i.e., under the City's approach the misclassification of a customer becomes the basis for preferential treatment at the expense of other customers. The City argues that their average rate per kWh has increased since being transferred to AL-TOU, and while this is true, it is not a meaningful comparison given that the City apparently received a subsidy while the OPL account was misclassified for Schedule A service. After reading the City's OPL example the Commission should ask whether billing errors and misclassifications that have worked in the customer's favor should become the basis for future rate design treatment in order to promote a desired outcome? In this instance, following the City's example, because OPL paid all energy rates as a misclassified Schedule A customer, then all energy rates should be extended to its proper Schedule AL-TOU classification. SDG&E believes that the Commission should reject the City's argument with respect to OPL because it appears to put subsidies for solar above the proper application of SDG&E's tariffs.

The City is concerned that there may be other accounts that could be reclassified from Schedule A to AL-TOU once the metering technology is installed, either as a result of solar installation or the installation of AMI. (City of San Diego, Testimony of Tom Blair, p. 9) SDG&E believes that this is a real possibility as well but it does not justify changing AL-TOU such that the accounts that have benefited from misclassification can extend their subsidies. The City has identified an issue that results from metering equipment being installed on site that is capable of measuring demand and energy, but the City would rather change the rates to continue to hide subsidies received by those accounts. The issue that the City addresses is applicable to customer load growth as well and following the City's logic a customer who experiences load growth should not be reclassified as Schedule AL-TOU, or the terms of Schedule AL-TOU should be modified in order to shift the costs of the load growth to other customers. SDG&E believes that solar installations should not be promoted by rate misclassification or billing errors but by reasonable cost based rates, including the continued application of the distribution NCD charge.

The City uses examples like the Bud Kearns Pool ("BKP") and Allied Gardens Pool ("AGP") to demonstrate why SDG&E's rates allegedly discourage energy efficiency measures. (City of San Diego, Testimony of Tom Blair, p. 9) The City's argument is that because the BKP and AGP have periods where they use little or no energy that the distribution NCD charges and higher average rate per kWh paid in those periods discourages energy efficiency measures. The City cites an average rate of well over $7 per kWh in 2 months to support its claim. The distribution NCD charges are appropriately billed to the customer and reflect the fact that distribution system is designed primarily to serve customer specific load. The fact that BKP and AGP reduce demand in a couple of months does not lower the investment in the distribution system to serve their NCD. From a review of Table 3 in the City's testimony it is apparent that the BKP account experienced significant bill reductions when the pool was closed, more than $1700 compared to its January billings. From a review of Table 4 it appears that the AGP bill dropped by about $1100 from the prior month. As for the City's concerns about $7/kWh average rate for the BGP, their claim is misleading at best. The higher average rate for those months is a mathematical result from dividing significantly lower total costs by a smaller amount of kWhs. The average rate "increase" means that distribution demand costs that are billed on a $/kW basis now make up a higher share of a lower total bill. Or to look at it another way, if there was any real meaning to this $7/kWh "average rate" then according to the City's logic they should have a strong financial incentive to install energy efficiency measures or if BKP had zero energy usage, then the City would have an infinite incentive to install energy efficiency measures.

The City's example of the Canyonside Recreation Center ("Canyonside") further demonstrates why SDG&E's distribution NCD charges are appropriate. (City of San Diego, Testimony of Tom Blair, pp. 11 - 13) Canyonside is a very poor load factor customer, using the City's Table 5, calendar year 2006 billings, it has about a 9% load factor. (City of San Diego, Testimony of Tom Blair, p. 12) Thus, Canyonside creates a significant demand (greater than 300 kW) on the SDG&E distribution system for a short period of time and in other hours utilizes distribution facilities at a much lower rate. SDG&E must design its distribution system to serve the large demands placed on it by Canyonside and that investment does not go away nor should it be shifted to other customers through the application of all energy charges. It is unclear to SDG&E why the City installed solar at a site with such a significant evening demand but the Commission should not require other customers to subsidize this solar investment through the elimination of the distribution NCD charge as proposed by the City. Instead, the continued use of SDG&E's distribution NCD charges with the ratchet helps to ensure that poor load factor customers like Canyonside pay for the cost of providing service to them.

The City's example of the Cabrillo Heights Park ("Cabrillio") is similar to Canyonside. (City of San Diego, Testimony of Tom Blair, pp. 13 - 14) Cabrillo is another account with a poor load factor, about 2% based on the 2006 billings set forth on the City's Table 6. (City of San Diego, Testimony of Tom Blair, p. 14) Yet Cabrillo's distribution NCD is large enough, greater than 40 kW, to classify it for service on Schedule AL-TOU. Again, SDG&E must size its distribution facilities to meet Cabrillo's NCD. Applying the distribution NCD charge ensures that customers like Cabrillo pay for the cost to serve them and are not subsidized by other customers.

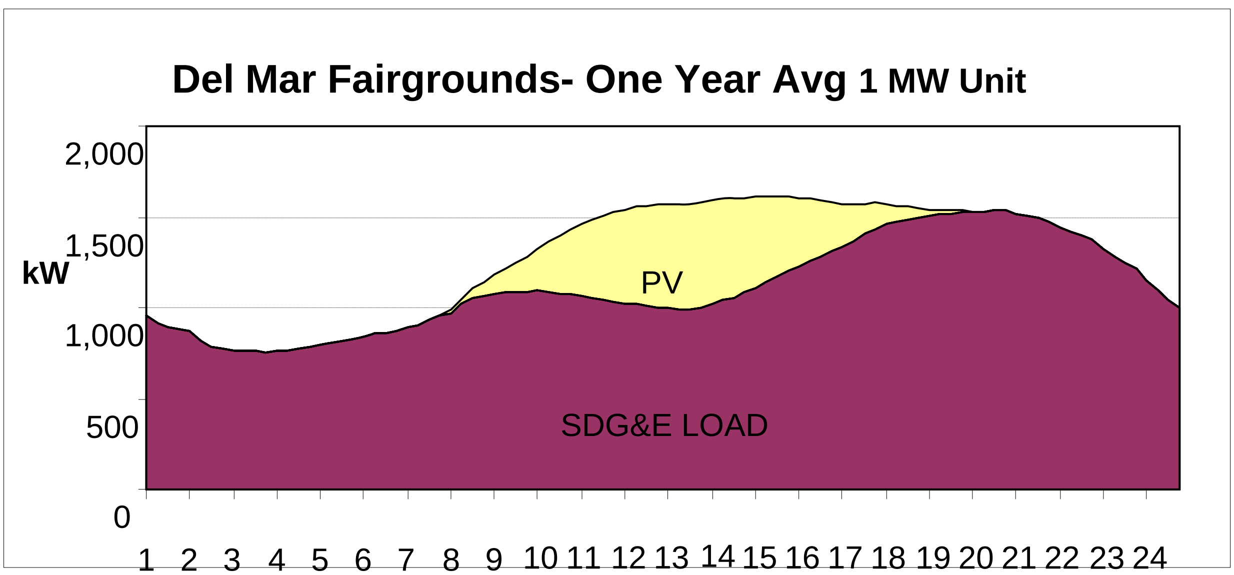
The City indicates that it seeks classification of its ball fields like Canyonside and Cabrillo for service on SDG&E's Schedule A. (City of San Diego, Testimony of Tom Blair, p. 14) This recommendation is addressed in the rebuttal testimony of SDG&E witness Mr. Robert W. Hansen.

The City indicates that it is uncertain regarding its potential investment in up to 600 MW of solar. (City of San Diego, Testimony of Tom Blair, pp. 14 - 15) SDG&E encourages the Commission to approve SDG&E's proposed C&I rate design, including the continued application of distribution NCD charges with the ratcheting mechanism, so that the City may utilize cost based rates in its decision making process.

The City recommends that the Commission adopt a voluntary energy only rate for C&I customers and points to rates currently in effect for PG&E as examples. (City of San Diego, Testimony of William A. Monsen, pp. 13 - 14) As stated previously in this testimony, and alluded to in the City's testimony, (City of San Diego, Testimony of William A. Monsen, p. 14), all energy rates will result in cost shifting such that higher load factor customers will provide greater subsidies for low load factor customers and for solar installations. SDG&E disagrees with the City regarding the treatment of the subsidy and believes that the proper venue for this solution is the Commission where increased subsidies for solar can be sought and recovered from all customers through a non bypassable charge.

As an alternative to an optional energy only rate for all C&I customers, the City proposes that the Commission approve an all energy rate for C&I customers applicable to customers with solar installations. (City of San Diego, Testimony of William A. Monsen, pp. 15 - 18) The City claims that SDG&E does not have a solar friendly rate for C&I customers and that rates with significant demand components are apparently prohibited by SB1. (City of San Diego, Testimony of William A. Monsen, pp. 15) The section of SB1 cited by the City refers to electricity production not the distribution component of electric service. SB1 encourages time variant cost based rates for electricity production such that both the solar customer and other customers paying for the subsidies provided by SB1 receive due value for the solar output and the avoided generation costs. Contrary to the City's position, SDG&E's proposes time variant, cost based commodity rate components for demand and energy, as well as an all energy commodity option through CPP. Schedule DG-R is an option for customers with qualifying solar and DG systems and which charges them on an energy only basis for commodity and replaces the maximum peak period distribution demand charges with energy charges. The PG&E rate cited by the City is the result of settlement and does not serve as precedent for SDG&E.

Vote Solar provides testimony from the Del Mar Fairground ("Del Mar") to provide a customer's perspective on SDG&E's demand charges and presumably to support their proposal for all energy rates. (Vote Solar, Testimony of Joseph Thomas Baker, pp. 38-39) Vote Solar indicates that they have seen virtually no demand charge savings from the solar installation at Del Mar. (Vote Solar, Testimony of Joseph Thomas Baker, p. 38) The reason that there have been virtually no distribution demand savings at Del Mar is that the solar installation does not offset the load placed by Del Mar on the distribution system. In fact, it does not even come close. Figure 3 below sets forth the annual average hourly load profile for Del Mar for 2006 and shows that the solar installation offsets only a fraction of the Del Mar hourly load. Del Mar is a low load factor customer with a very high seasonal load resulting from the fairground operations. SDG&E's distribution NCD charges are appropriately applied to Del Mar because SDG&E must design its distribution facilities to serve their peak load. Figure 4 below sets forth the 2006 monthly consumption and monthly max demands of Del Mar and illustrates the poor load factor and variability in their load. The continued application of the distribution NCD charge and the associated ratchet is precisely for customers like Del Mar so that they pay for the costs to serve them. The fact that their solar installation does not offset their distribution demands in other periods is not an indictment of SDG&E's continued practice of applying distribution NCD charges but an example of the limitations of solar to offset a customer's load.



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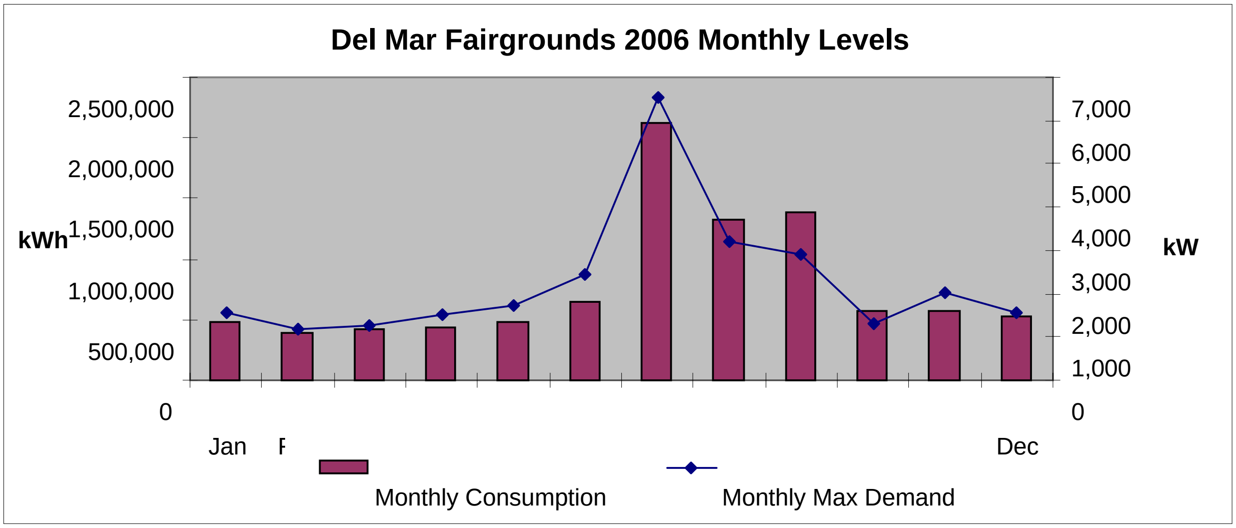

Vote Solar presents testimony from Macy's to provide a customer's perspective on SDG&E's demand charges and presumably to support their proposal for all energy rates. (Vote Solar , Testimony of Joseph Thomas Baker, pp. 39 - 40) Vote solar indicates that SDG&E's demand charges are extremely hard to predict but this is because of the difficulty in predicting the solar output and is not due to the actual $/kW demand charges. Vote Solar claims that it is SDG&E's demand charges that reduce Macy's ability to invest in solar, but it is the solar generation that does not offset Macy's distribution demands. Despite Macy's laudable goals of promoting solar, their proposal is to shift the costs of serving them (that solar generation does not avoid or reduce) on to other customers through all energy charges.

Vote Solar presents the testimony of Solar Power Partners, Inc. to provide an installer's perspective on SDG&E's demand charges and presumably to support their proposal for all energy rates. (Vote Solar, Testimony of Todd Michaels, pp. 40 - 43) Vote Solar indicates that SDG&E's high demand charges are the difference in the growth of solar in its territory versus other IOUs' service areas. (Vote Solar, Testimony of Todd Michaels, pp. 42 - 43) Vote Solar indicates that solar will reliably offset kWhs but not demand. (Vote Solar, Testimony of Todd Michaels, p. 41) Solar generation has limitations with respect to offsetting a customer's load, during daylight hours and of course at night, and the Vote Solar position of all energy rates allows the solar generation to credit kWhs generated to the grid in one period against kWhs that they consume in other periods despite the fact that solar generation does not offset SDG&E's distribution costs in other periods. Thus, the Vote Solar position is primarily one of cost avoidance and shifting to other customers. Other IOUs have apparently provided rate options through settlement to support the solar industry, but SDG&E believes that all of its customers are best served by cost based rates and that additional subsidies required by solar generation should be sought from the Commission and recovered from all customers through a nonbypassable charge. However, SDG&E considers Schedule DG-R as a reasonable compromise on this issue. Schedule DG-R is applicable to solar and DG units that meet the requirements of SGIP and are up to 500 kW in size. Schedule DG-R replaces the proposed commodity demand charge with an energy component and replaces the distribution maximum peak period demand charges with energy components.

Vote Solar indicates that demand and customer charges thwart energy efficiency efforts because they are difficult or impossible to avoid. (Vote Solar, Testimony of Robert Redlinger, pp. 43-45) SDG&E's customer costs are fixed in nature and do not vary with a customer's energy or demand usage. Vote Solar's proposal would shift the costs for billing and metering on to other customers for something that solar technology does not otherwise allow the customer or SDG&E to avoid.

D. Solar Alliance

Solar Alliance provides a discussion of the background of solar energy issues in California and the issues that lie ahead. SDG&E disagrees with how the Solar Alliance proposes to implement its four main recommendations. (Solar Alliance, Testimony of R. Thomas Beach, pp. 3 -4)

SDG&E agrees in general with the Solar Alliance recommendation 1 that the tariff should create the maximum incentive for ratepayers to install solar systems whose peak production coincides with California's peak electricity demands, but SDG&E disagrees that energy only charges are the best approach. Energy only charges would increase the incentive to solar customers but they also allow the solar customer to avoid costs that SDG&E does not avoid and thus shifts cost recovery to other customers. Solar Alliance provides an example where a solar customer's generator may not provide sufficient output to offset load due to cloudy conditions such that a single 15 minute outage could reduce their value despite the remainder of the month's operation at otherwise higher output. (Solar Alliance, Testimony of R. Thomas Beach, pp. 15-18) The Solar Alliance example may not represent the true nature of solar electricity production over the course of the month with the result being that solar reliability is dependent on more than one 15 minute cloud covering during the month. It appears that the Solar Alliance realizes this in their discussion on p. 18 of their testimony, but SDG&E must serve the customer load regardless of the load profile or size of the customer's solar. SDG&E proposes rates that recover costs from all customers based on how they are incurred, including the continued application of the distribution NCD charges.

SDG&E agrees with Solar Alliance recommendation 2 regarding ratepayers receiving due value for their contribution to the purchase of solar energy systems but disagrees with the part that recommends minimal use of demand charges. (Solar Alliance, Testimony of R. Thomas Beach, p. 4) To the extent warranted according to cost causation principles SDG&E believes that demand charges should be applied even for solar customers in order to minimize cost shifting to and subsidies from other customers. Thus, SDG&E recommends the continued application of the distribution NCD charges and its proposed commodity demand charge.

SDG&E agrees with Solar Alliance recommendation 3 regarding ratepayers having an incentive for energy efficiency through TOU rates but disagrees with the part that recommends all volumetric rates. (Solar Alliance, Testimony of R. Thomas Beach, p. 4) SDG&E is concerned that all volumetric rates do not reflect cost causation principles and will shift costs from low load factor customers for costs that SDG&E does not avoid, e.g., distribution facilities. Thus, SDG&E promotes TOU rates but also recommends the continued practice of applying distribution NCD charges and its proposed commodity demand charge.

SDG&E agrees with Solar Alliance recommendation 4 that would allow customers the option of TOU tariffs, and SDG&E currently allows C&I customers different TOU rate schedules as well as SDG&E's proposed schedule DG-R. SDG&E views the applicability of this recommendation to residential customers only to the extent that all of the residential TOU optional rates are exempt from AB1X.

E. SDG&E's Rates and Compliance with SB1

The City of San Diego claims that SDG&E's rates do not comply with the provisions of SB1 because of the use of demand charges and that they do not provide the maximum incentive for solar producers at the time of system peak. (City of San Diego, Testimony of William A. Monsen, pp. 15-18)

SDG&E's C&I rates provide the maximum incentive to solar generation during system peak by pricing the commodity rate components at their time variant cost. The objection from the City is that an all energy rate instead of rates with demand components will result in higher peak period energy charges and thus will provide greater incentives to solar customers. SDG&E agrees with this argument to the extent that "incentives" are replaced with "subsidies", however this is not consistent with how costs are incurred on SDG&E's system. To the extent that solar generation is able to offset the customer's peak period load then the customer receives the maximum incentive and SDG&E is able to avoid costs as well. But if solar generation has no effect on distribution demand during hours when solar does not generate or it does not consistently offset a customer's own load during peak periods then solar customers should pay their share of costs for using the system rather than be granted additional subsidies from customers by distorting the rate design.

This concludes my rebuttal testimony.

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

Application No. 07-01-047
Exhibit No.: (SDG&E-______)

REBUTTAL TESTIMONY

OF THOMAS O. BIALEK

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY

OF

THOMAS O. BIALEK

I. INTRODUCTION

The purpose of my rebuttal testimony is to address the issue of distribution non coincident demand charges from a distribution system perspective.

A. Demand Charges are required for recovering cost of installing infrastructure to serve commercial and industrial customers.

SDG&E designs and installs electric infrastructure to support customer demands that exist in two forms, on-peak demand and non-coincident demand. Individual customer on-peak demands aggregate to system coincident demand. Non-coincident demand is anytime demand, specific to an individual customer. SDG&E's design criteria require that the distribution system be designed to support both on-peak coincident demand and non-coincident demand. A typical distribution circuit consists of feeders, branches, and services. Feeders serve as the backbone of a circuit designed to support on-peak coincident demand. Branches are designed to serve customers in support of aggregate non-coincident demands. Services such as conductors, transformers and meters serve individual customers in support of their non-coincident demand. SDG&E's distribution system, captured in 2007, consists of 3,626 miles of feeders, 12,899 miles of branches and 10,670 miles of services. The total of branches and services is 23,569 miles or 87% of the distribution system; it also means that 87% of the distribution system is designed to support customer non-coincident demand. From an investment stand-point, using streamline construction unit costs of $250,000 per feeder mile, $150,000 per branch mile and $40,000 per service mile, SDG&E has invested approximately $906,500 million in feeders and $2,575,000 million in branches and services. The total investment on branches and services is 74% of investments; it also means that 74% of all investments were to support customer non-coincident demand.

It's undisputable that infrastructure is designed and installed to support non-coincident demand, and its associated cost is much greater than those for on-peak coincident demand. It's also indisputable that the design and installation of electric infrastructure are not based on energy consumption. It's even more compelling that energy consumption should not be used to recover infrastructure investment on commercial and industrial for the following reason:

- Demand and consumption of commercial and industrial customers vary widely and dis-joint. Commercial and industrial demand varies from tens of kilowatts to thousands of kilowatts, and consumption does not change accordingly with demand. Commercial and industrial whose operation is seasonal (e.g. water park, recreational facilities, swimming facilities, Qualcomm stadium, and Petco park) are great examples where demand and consumption are dis-joint where demand is high but consumption low. SDG&E's investment on infrastructure would be similar for two commercial customers with comparable non-coincident demand regardless of their operation; nevertheless energy consumption would be much less for a commercial with seasonal operation than a commercial with year-round operation. In absence of the non-coincident demand charges, SDG&E would not be able to recover the infrastructure investment to support non-coincident demand. Or if energy consumption rates were adjusted for recovering infrastructure investment, then it would be unfair for year-round commercial to subsidize for seasonal commercial.

In summary non-coincident demand charges are essential and should be stand alone charges for recovering cost of installing infrastructure to support non-coincident demand because (1) investment on infrastructure to support non-coincident demand is the largest of all investments, (2) investment on infrastructure is not based on consumption, (3) using energy consumption to recover infrastructure investment would create huge disparity and unfairness for customers.

B. Solar facilities do not reduce non-coincident peaks and demand charges are not stand-by charges.

Solar facilities saved the City sizeable amount on energy consumption; they also help the City in reducing on-peak demand charges. Solar facilities however were not able to reduce non-coincident demand especially for facilities whose operation continued outside the window where solar facilities were able to generate power. SDG&E system is always available to support the load when solar facilities are not, and it's the same permanent system installed specifically for the customer. In conclusion solar facilities were not able to reduce non-coincident demand or to help SDG&E in reducing infrastructure investment.

Non-coincident demand charges are not de facto standby charges because SDG&E's system is the primary source to plants with solar facilities, not the stand-by source. Per our estimate, solar facilities would be able to generate electricity at best 10 hours per day, therefore SDG&E system will be serving load 14 hours per day, a period longer than the solar facilities. Therefore SDG&E is the primary source (not the stand-by source) utilized more than 50% of the time.

This concludes my rebuttal testimony.

QUALIFICATIONS

My name is Thomas O. Bialek, P.E. My business address is 8316 Century Park Court, San Diego, California 92123. I am employed by San Diego Gas & Electric Company ("SDG&E") as a Principal Engineer in electric Transmission and Distribution Planning. My present responsibilities involve a technical oversight role on distribution issues including equipment, operations, planning and distributed generation on behalf of SDG&E. These activities generally include technical review, policy development and strategic planning of distribution systems. I am also responsible for the preparation of exhibits and proposals for regulatory proceedings related to my areas of responsibility.

I have been employed by SDG&E since 2000 and have held various positions with other North American utilities and equipment manufacturers subsequent to that time. My experience includes electric utility design, planning and operation equipment design, development and manufacturing.

I received a Bachelor and Master of Science Degree in Electrical engineering from the University of Manitoba in 1982 and 1986 respectively. I am currently completing my doctoral Thesis in electrical Engineering in association with Mississippi State University. I am a registered Professional engineer, Electrical Engineering, in the State of California. In addition, I have actively participated in all the distributed generation rulemakings and workshops since 1998.

I have previously testified before the California Public Utilities Commission.

Application of SAN DIEGO GAS & ELECTRIC)
COMPANY for Authority to Update Marginal Costs,)
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Application No. 07-01-047
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REBUTTAL TESTIMONY

OF ROBERT W. HANSEN

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTLITIES COMMISSION
OF THE STATE OF CALIFORNIA

SEPTEMBER 24, 2007

PREPARED REBUTTAL TESTIMONY

OF

ROBERT W. HANSEN

The purpose of my rebuttal testimony is to respond to the City of San Diego's (City's) testimony regarding: (1) the applicability of SDG&E's current Schedule A rate for outdoor sports facilities, (2) the City's request for an induction lighting rate option, and (3) the City's preference to have small-use service locations unmetered.

Schedule A is SDG&E's standard service option for commercial customers with demands less than 20 kW. By approval of SDG&E Advice Letter 1880-E (Resolution E-4085, dated June 21, 2007), registered non-profit entities with lighting load such as Little League parks with demands of up to 100 kW are eligible to request service under Schedule A. The City of San Diego contends that applicability of Schedule A should be further expanded to include "similarly situated" City sport fields. (Ref, City of San Diego witnesses Blair at page 14, Monsen at pages 34–36). The City's preferable proposal, however, is that demand charge structures be entirely "optional" for all customers with demands up to 500 kW. (Ref. Monsen at page 36)

SDG&E believes that the City's proposal extends far beyond the narrow exception and limited subsidy that was approved by the Commission in Resolution E-4085. First, the example cited by the City, a ball field complex with a maximum demand in excess of 370 kW, would not qualify even if it were deemed to be "similarly situated" as a non-profit Little League ball park. SDG&E had no intention of expanding the small commercial energy-only rate structure to such a peaky, high demand service location. SDG&E's current very limited exemption and subsidy is only for ball fields registered as non-profit entities (under section 501(c)(3)) with lighting loads.

A demand charge rate structure is the preferred rate structure for C&I customers and should continue to be applied to City-owned sport fields. Portraying SDG&E's proposed demand/energy rate structure as being somehow inferior to a flat energy-only rate structure for a 500kW customer is outrageous. (Ref. Monsen at page 12 and at pages 34-36) A demand charge rate structure is an extremely common and proven method of pricing electricity. It can provide a strong incentive for a customer to control their peak demand on the system and to flatten their usage profile.

To contend that demand charges are inferior to an energy-only structure because demand charges don't provide the proper incentive for low load factor customers to further conserve energy is a weak argument. (Ref. Monsen at page 12) The City's example of a low load-factor ball field with demands in excess of 370 kW (when adjusted for Solar PV installed) is the prime example of why a demand charge structure is necessary. Customers like the City of San Diego need price signals that reflect the demand that they place on the system. SDG&E must install and maintain a distribution system capable of serving the City's maximum demand regardless of when it occurs. An energy-only rate structure would greatly under collect the costs of providing service to very low load-factor locations as presented by the City of San Diego (based on data in Blair Table 5).

In summary, SDG&E is already obligated to design a "cost-based" lighting rate for such customers in its next rate proceeding. During that proceeding the energy-only rate will be reviewed to more appropriately reflect the time-of-use profile and peak demands of ball fields with lighting. SDG&E intends to revisit the exception granted to qualified non-profit entities as directed in Resolution 4085 in the next rate proceeding.

The City also proposes that SDG&E develop an "induction lighting rate" in its next rate design proceeding. (Ref. Testimony of Tom Blair at page 16). Mr. Blair states that the City is currently considering the possibility of installing induction lighting on its street lights. (Id.)

In fact, SDG&E induction lighting rate options are currently available to the City of San Diego.[1] The current lighting rate options have been available for several years, and were originally implemented by SDG&E ***at the request*** of the City of San Diego. The City should clarify its lighting service requests and concerns and simply communicate its concerns with their assigned SDG&E account representative. If the City now believes SDG&E's approved induction lighting rate options are not consistent with the City's new plans for induction lighting, SDG&E would be glad to consider additional induction lighting options in a future rate proceeding.

The City states that it has 325 meter locations with no annual usage, which the City would prefer to be unmetered. The City indicates that the meter locations are needed for switches and other ancillary power needs. (Ref. Testimony of Tom Blair at pages 16-17)

SDG&E notes that the metered locations referenced by the City are active accounts served under Schedule A. All active accounts under Schedule A are applied a monthly fixed

[1] Induction lighting rates for 55 watt and 57 watt facilities are available under Schedule LS-2, which is applicable to customer-owned facilities.

charge intended to recover a portion of SDG&E's fixed costs of providing service. While SDG&E does offer customers the option of unmetered service under Schedule UM, the current unmetered rate option is not applicable to situation that the City describes. Schedule UM has fixed costs built into its monthly charges and it would not provide 100 percent bill savings that the City is apparently seeking. SDG&E will consider the applicability of such low-used meter locations during its deployment of advanced meters.

This concludes my prepared rebuttal testimony.

ATTACHMENT RWH-A
SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT
GRC Phase 2 (A.07-01-047)

UNBUNDLED RATES FOR SCHEDULE DR - WITH SEPARATE TRAC RATES
BASED ON RATES EFFECTIVE JULY 1, 2007
($ per kWh)

DESCRIPTION (A)	TRANSMISSION (B)	DISTRIBUTION (C)	PPP (D)	NUCLEAR DECOMM. (E)	FTA (F)	CTC (G)	RS (H)	TRAC (aka 2006 RDSC) (I)	TOTAL UDC (J)	GENERATION (K)	DWR BOND (L)	TOTAL (M)
Summer												
Baseline Energy	0.00945	**0.05754**	0.00615	0.00046	0.00513	0.00219	0.00602	**(0.04080)**	0.04614	0.07784	0.00469	**0.12867**
101% to 130% of Baseline	0.00945	**0.07068**	0.00615	0.00046	0.00513	0.00219	0.00602	**(0.03377)**	0.06631	0.07784	0.00469	**0.14884**
131% to 200% of Baseline	0.00945	**0.07068**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.04296**	0.14304	0.07784	0.00469	**0.22557**
201% to 300% of Baseline	0.00945	**0.07068**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.05203**	0.15211	0.07784	0.00469	**0.23464**
Above 300% of Baseline	0.00945	**0.07068**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.06786**	0.16794	0.07784	0.00469	**0.25047**
Winter												
Baseline Energy	0.00945	**0.05754**	0.00615	0.00046	0.00513	0.00219	0.00602	**(0.01645)**	0.07049	0.05349	0.00469	**0.12867**
101% to 130% of Baseline	0.00945	**0.06295**	0.00615	0.00046	0.00513	0.00219	0.00602	**(0.00169)**	0.09066	0.05349	0.00469	**0.14884**
131% to 200% of Baseline	0.00945	**0.06295**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.05961**	0.15196	0.05349	0.00469	**0.21014**
201% to 300% of Baseline	0.00945	**0.06295**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.06843**	0.16078	0.05349	0.00469	**0.21896**
Above 300% of Baseline	0.00945	**0.06295**	0.00615	0.00046	0.00513	0.00219	0.00602	**0.08651**	0.17886	0.05349	0.00469	**0.23704**

Attachment RWH – B

ATTACHMENT RWH-B
SAN DIEGO GAS & ELECTRIC COMPANY - ELECTRIC DEPARTMENT
GRC Phase 2 (A.07-01-047)

ILLUSTRATIVE UNBUNDLED RATES FOR SCHEDULE DR - WITH TRAC INCLUDED WITH DISTRIBUTION
BASED ON RATES EFFECTIVE JULY 1, 2007
($ per kWh)

DESCRIPTION (A)	TRANSMISSION (B)	DISTRIBUTION (C)	PPP (D)	NUCLEAR DECOMM. (E)	FTA (F)	CTC (G)	RS (H)	(I)	TOTAL UDC (J)	GENERATION (K)	DWR BOND (L)	TOTAL (M)
Summer												
Baseline Energy	0.00945	**0.01674**	0.00615	0.00046	0.00513	0.00219	0.00602		0.04614	0.07784	0.00469	**0.12867**
101% to 130% of Baseline	0.00945	**0.03691**	0.00615	0.00046	0.00513	0.00219	0.00602		0.06631	0.07784	0.00469	**0.14884**
131% to 200% of Baseline	0.00945	**0.11364**	0.00615	0.00046	0.00513	0.00219	0.00602		0.14304	0.07784	0.00469	**0.22557**
201% to 300% of Baseline	0.00945	**0.12271**	0.00615	0.00046	0.00513	0.00219	0.00602		0.15211	0.07784	0.00469	**0.23464**
Above 300% of Baseline	0.00945	**0.13854**	0.00615	0.00046	0.00513	0.00219	0.00602		0.16794	0.07784	0.00469	**0.25047**
Winter												
Baseline Energy	0.00945	**0.04109**	0.00615	0.00046	0.00513	0.00219	0.00602		0.07049	0.05349	0.00469	**0.12867**
101% to 130% of Baseline	0.00945	**0.06126**	0.00615	0.00046	0.00513	0.00219	0.00602		0.09066	0.05349	0.00469	**0.14884**
131% to 200% of Baseline	0.00945	**0.12256**	0.00615	0.00046	0.00513	0.00219	0.00602		0.15196	0.05349	0.00469	**0.21014**
201% to 300% of Baseline	0.00945	**0.13138**	0.00615	0.00046	0.00513	0.00219	0.00602		0.16078	0.05349	0.00469	**0.21896**
Above 300% of Baseline	0.00945	**0.14946**	0.00615	0.00046	0.00513	0.00219	0.00602		0.17886	0.05349	0.00469	**0.23704**