BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE
STATE OF CALIFORNIA

Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902–E) for Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design	)))))	Application 11-10-002 (Filed October 3, 2011)

Prepared Direct Testimony of R. Thomas Beach on behalf of the Solar Energy Industries Association

June 12, 2012

EXECUTIVE SUMMARY OF RECOMMENDATIONS

This testimony presents the recommendations of the Solar Energy Industries Association (SEIA) concerning the design of San Diego Gas & Electric's (SDG&E) electric rates over the next three years.

In this case, SDG&E is proposing changes to the structure of its standard Schedule DR residential rate, with the goal of reducing the upper-tier rates that apply to the residential customers who use the most energy. SEIA opposes the changes that SDG&E is proposing – most importantly, SDG&E's proposal to replace its residential minimum bill with a fixed monthly customer charge of $3.00 per month and its proposal to combine its upper Tier 3 and Tier 4 rates into a single Tier 3 rate. In its recent order in the Pacific Gas and Electric (PG&E) general rate case (GRC), D. 11-05-047, the Commission squarely confronted its policies concerning residential rate design, with PG&E and others expressing the same concern about residential rates that SDG&E has expressed in this case. D. 11-05-047 rejected PG&E's proposed $3.00 per month customer charge, and the Commission maintained a four-tier, increasing-block rate design for PG&E. SEIA submits that SDG&E has provided no reasonable grounds to depart from the rate design policies adopted in the PG&E case. The Commission should moderate SDG&E's residential rate design proposal in order not to undermine the state's key policy goals of strongly encouraging both energy efficiency measures and the development of distributed generation (DG) sources such as solar. The Commission should maintain the existing SDG&E four-tier rate structure for Schedule DR, and should keep the current differential of $0.02 per kWh between the Tier 3 and 4 rates.

Senate Bill 1 (SB 1) authorized the Commission to develop time-of-use (TOU) tariffs that create "the maximum incentive for ratepayers to install solar energy systems" that serve peak electric demands. In this case, SEIA recommends that the Commission should recognize the legislative encouragement embodied in SB 1, in the following ways:

- SDG&E should recognize that the upstream, substation portion of SDG&E's distribution system is driven largely by coincident, peak demands. As a result, a significant portion of SDG&E's distribution costs should be allocated on a time-of-use basis.

- SEIA supports SDG&E's proposal to extend through this GRC cycle its Schedule DG-R rate for commercial customers who install solar or other renewable DG. The Commission adopted Schedule DG-R rates for SDG&E's commercial solar and DG customers in the last SDG&E GRC Phase 2 case.

- SEIA also supports SDG&E's plan to ask the Federal Energy Regulatory Commission (FERC) to change the design of SDG&E's transmission rates to be based on time-related charges instead on non-coincident demand charges

NCDCs). This change makes sense because transmission costs clearly are driven by coincident system peak demands. Until this change in FERC-approved rates takes place, and to avoid significant NCDC increases for Schedule DG-R customers, SDG&E should provide an additional reduction in the DG-R NCDC, by setting this demand charge at 50% of the total NCDC in Schedule AL-TOU.

Finally, this testimony presents more transparent and up-to-date calculations of marginal energy and generation capacity costs than those advanced by SDG&E or DRA. Natural gas and electric market prices are lower today than when SDG&E filed its testimony in February 2012. Accordingly, SEIA's marginal energy costs are determined from updated prices for 2013-2014 in the forward natural gas and electricity markets, combined with the most recent data on hourly price profiles in southern California from the California Independent System Operator's (CAISO) day-ahead market. For marginal generation capacity costs, SEIA recognizes that SDG&E continues to add significant amounts of renewable generation capacity to meet the statutory requirements of California's Renewable Portfolio Standard (RPS). SDG&E also faces a need for local capacity in the San Diego load pocket, particularly in the event that the steam generator problems at the San Onofre Nuclear Generation Station (SONGS) result in a lengthy outage or cause the de-rating of that plant's capacity. In these circumstances, it makes no sense to discount SDG&E's marginal generation capacity costs based on an alleged lack of an immediate need for new capacity. Instead, a reasonable proxy is to set SDG&E's marginal generation capacity cost at the full annualized fixed costs of a new combustion turbine, which SEIA estimates, using the average of two independent approaches, to be $157 per kW-year at the transmission voltage.

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I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae*, which is **Attachment RTB-1** to this testimony.

Q: Have you testified previously before this Commission?

A: Yes, I have. A current list of the testimony that I have filed before this Commission is included in my CV. I also have testified before the state public utility commissions in Colorado, Oregon, Nevada, New Mexico, and Virginia.

Q: Please describe more particularly your experience on cost allocation and rate design issues for electric utilities.

A: As reflected in my CV, I have extensive experience on electric cost allocation and rate design issues in California. Over the last decade, I have filed testimony and participated actively in most of the Phase II general rate case (GRC) proceedings for San Diego Gas and Electric (SDG&E) and the other major investor-owned utilities (IOUs) in California, Pacific Gas and Electric (PG&E) and Southern California Edison (SCE).

Q: On whose behalf are you testifying today?

A: I am appearing on behalf of the Solar Energy Industries Association (SEIA).[1]

SEIA is the national trade association of the United States solar industry. Through advocacy and education, SEIA and its 1,100 member companies work to make solar energy a mainstream and significant energy source by expanding markets, removing market barriers, strengthening the industry, and educating the public on the benefits of solar energy. Effective on January 1, 2012, the Solar Alliance merged with SEIA. Through a notice filed on January 6, 2012, SEIA informed the Commission of the merger with the Solar Alliance and the necessary change in party name for participation in this proceeding.

Q: Please describe in more detail your experience testifying on issues related to the solar industry.

A: With respect to solar issues, I have filed testimony on behalf of the Solar Alliance or SEIA in the Phase 2 cost allocation / rate design proceeding of each IOU's most recent general rate case: A. 11-06-007 (SCE), A. 10-03-014 (PG&E), A. 08-03-002 (SCE), and A. 07-01-047 (SDG&E), addressing rate design and cost allocation issues of concern to

[1] The positions stated in this testimony represent the position of the SEIA as an organization, but not necessarily the views of any particular member with respect to any issue.

the solar industry. In the fall of 2006, PV Now (a predecessor of the Solar Alliance) retained me to coordinate the solar industry's participation in an intensive, Commission-sponsored process to develop the Handbook with the program and process details for the California Solar Initiative (CSI). For the California Solar Energy Industries Association (CalSEIA), I have testified before the Commission in R. 04-03-017 on the cost-effectiveness of solar incentives. Finally, I am the owner and operator of a 2.4 kW photovoltaic (PV) system that has been installed on my family's home in Kensington, California since January 2003. We are interconnected to the PG&E system as a net metering customer under PG&E's E-7 time-of-use (TOU) tariff. Our PV system provides most of my family's electrical requirements, and has resulted in a zero net energy bill from PG&E for five of the past nine years. On my own behalf, I have participated before this Commission in R. 06-03-004 on the design of the CSI program and in R. 04-04-026 and R. 06-03-004 on issues concerning the renewable energy credits for customer-owned distributed generation. Finally, as referenced in my CV, I also have testified on a variety of solar issues before the state public utilities commissions in Colorado, New Mexico, and Virginia.

Q: What is the purpose of your testimony?

A: My testimony presents SEIA's recommendations on a number of rate design issues in this SDG&E general rate case that are of significant concern to the solar industry in California.

First, SEIA is concerned with SDG&E's proposal to restructure its Schedule DR residential tariff. SDG&E's proposal raises many of the same issues concerning residential rate design that recently were thoroughly litigated in PG&E's GRC Phase 2 case (A. 10-03-014). The Commission decided that case just over a year ago, in D. 11-05-047. SEIA is concerned that SDG&E's proposals in this case would go well beyond the Commission's determinations on the same issues for PG&E in D. 11-05-047. That

order adopted a careful balance between, first, rate relief for high-usage, upper-tier customers and, second, the state's important and comprehensive efforts to encourage both the efficient use of energy and the development of distributed generation resources, including solar.

Second, Senate Bill 1 (SB 1), which was enacted in 2006 and which provides the statutory basis for the California Solar Initiative, authorizes the Commission to design time-of-use (TOU) tariffs that provide "the maximum incentive" for solar customers to install systems that produce power when California's demand for electricity peaks. In other recent cost allocation / rate design Phase 2s of utility GRCs, the Commission has taken a variety of actions to develop TOU tariffs that respond to SB 1. These steps include the adoption in the last SDG&E GRC Phase 2 of the Schedule DG-R rate for commercial and industrial (C&I) customers who install renewable DG. My testimony discusses specific ways in which SB 1 should guide the design of SDG&E's commercial TOU rates.

Finally, I recommend calculations of SDG&E's marginal energy and generation capacity costs that differ from SDG&E's proposals, that use updated market data, and that are simpler and more transparent than those that SDG&E presents.

II. POLICY BACKGROUND

A. California's "Loading Order" for New Electric Resources

Q: Please review the priorities that California policymakers have established for the utilities' procurement of new electric resources.

A: The Commission and the California Energy Commission (CEC) have established the

state's procurement priorities through the "loading order" for electric resources set forth in the state's Energy Action Plans.[2] The state's first priority is to encourage energy efficiency; the second priority is to stimulate the development of renewable generation, including on-site DG such as solar PV that typically is located behind the retail meter. California is the acknowledged national leader in both energy efficiency – with the often-cited accomplishment of keeping per capita energy use constant for the past three decades[3] – and solar energy, with California leading the nation in installed solar PV capacity.

B. The California Solar Initiative

Q: Please describe the creation and purpose of the California Solar Initiative (CSI).

A: The Commission created the CSI in January 2006 (D. 06-01-024) with a goal to install 3,000 MW of distributed solar facilities by the end of a ten-year period (2007 - 2016), with the ultimate goal of effecting a market transformation that will make solar PV systems cost-effective in California without incentives. The CSI built upon the success of earlier CEC- and CPUC-administered incentive programs for behind-the-meter solar that the Legislature funded in AB 1890 (1998) and AB 970 (2001).

The CSI provides stable, consistent funding for solar incentives based on a schedule of incentives that decline over time as targets are achieved for installed solar megawatts. Decision 06-01-024, at page 2, highlighted the following objectives for the CSI program:

- adding clean, renewable energy to peak demand resources;

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[2] The state's adopted "loading order" for new resources is presented in the Energy Action Plan II adopted by this Commission and the California Energy Commission in October 2005, at page 2. The Energy Action Plan II can be found at http://docs.cpuc.ca.gov/word_pdf/REPORT/51604.pdf.

- mitigating risk by diversifying the state's energy portfolio; and
- reducing the need for transmission and distribution system additions.

In its August 2006 order adopting the CSI program details (D. 06-08-028), the Commission reiterated these goals, and acknowledged at page 29 that "one of the key goals of the CSI is to produce valuable energy during peak times."

C. Senate Bill 1 Sets a Policy Goal of "Solar-friendly" TOU Tariffs.

Q: Senate Bill 1 (SB 1), enacted in August 2006, provided a statutory basis for the CSI program. Please explain the provision of SB 1 related to the tariffs under which CSI customers take electric service.

A: SB 1 added P.U. Code Section 2851(a)(4), which required time-variant pricing for all solar customers. This code section originally specified as follows:

> ... the commission shall develop a time-variant tariff that creates the maximum incentive for ratepayers to install solar energy systems so that the system's peak electricity production coincides with California's peak electricity demands and that assures that ratepayers receive due value for their contribution to the purchase of solar energy systems and customers with solar energy systems continue to have an incentive to use electricity efficiently.

The statute then stated that the time-variant tariff also does not need to comply with the rate cap that the Legislature implemented in 2001 for a residential customer's electric use below 130% of that customer's "baseline" amounts. This rate cap was a key element of the Assembly Bill 1x (AB 1x) rate protections adopted during the 2000 - 2001 California energy crisis.

Q: Discuss the difficulties that arose with SB 1's requirement that solar customers take

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[3] This accomplishment is shown in

service under a TOU tariff.

A: Beginning shortly after the CSI program went into effect on January 1, 2007, it became clear that SB 1's requirement to take service under a TOU tariff presented a major barrier to the participation in the CSI for many small residential and commercial customers – particularly customers who had no prior experience with TOU rates and thus who faced significant uncertainty in the time profile of their electric usage, or customers moving from non-TOU rates with usage tiers to TOU rates without such tiers.

Q: How did the Commission and Legislature react to this problem?

A: In D. 07-06-014, the Commission suspended the requirement that all solar customers must take service under TOU rates, until TOU rates that met the criteria set forth in Section 2851(a)(4) of SB 1 could be developed in the Phase 2 GRC proceedings for each utility. The Legislature also acted on this issue. AB 2768 eliminated the requirement that solar customers must use a TOU tariff, and changed the word "shall" to "may" in the first sentence of P.U. Code Section 2851(a)(4), cited above.

Q: Are there factors that you anticipate will cause solar customers increasingly to use TOU tariffs, even if TOU pricing is not mandatory?

A: Yes. In particular, the utilities' programs to install advanced meters for all customers will allow customers to understand the time-of-use profile of their own usage, increase the ability of customers to elect TOU pricing, and foster a wider appreciation of the benefits of TOU pricing, both with and without solar PV. The Commission approved SDG&E's deployment of advanced meters in D. 07-04-043.

The Lawrence Berkeley National Laboratory (LBNL) has investigated whether residential solar customers would realize greater bill savings under a standard residential tariff or a TOU rate, as part of a study on net energy metering (NEM). The LBNL

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http://www.energy.ca.gov/commissioners/rosenfeld_docs/rosenfeld_effect/presentations/NRDC.pdf , at

researchers concluded that TOU tariffs produce greater bill savings for residential solar customers than do non-TOU rate options.[4]

D. Recent GRCs Address SB 1-compliant TOU Tariffs.

Q: Has the Commission considered the design of SB-1-compliant TOU tariffs in the rate design phases of the general rate cases for the California electric utilities?

A: Yes, it has, in the Phase 2 portions of the most recent GRCs for all three IOUs, including SDG&E's last Phase 2 case, A. 07-01-047.

For example, the settlement in Phase 2 of the last SDG&E GRC Phase 2 responded to SB 1 in several respects. First, the settlement created a Schedule DG-R for large commercial customers who install distributed generation capable of serving at least 10% of their peak demand. The rates for Schedule DG-R feature higher TOU energy charges and reduced demand charges. All generation costs are collected on a volumetric basis, with no commodity demand charges. The non-coincident demand charge is set at 50% of the equivalent non-coincident demand charge for other commercial schedules, with the remaining distribution costs for Schedule DG-R recovered through a flat (non-time varying) energy charge. Second, the SDG&E settlement provided residential customers who install solar with the choice of two TOU rate schedules, including a new TOU schedule providing increased bill savings for smaller usage residential customers. The Commission approved the SDG&E settlement in D. 08-02-034, finding that the settlement's terms were consistent with P.U. Code § 2851(a)(4).[5]

Q: Has the Commission also moved to create more "solar-friendly" rates for SCE and PG&E customers in the recent GRC Phase 2 cases for those utilities?

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page 3 of 24.

[4] The LBNL NEM study is available at http://eetd.lbl.gov/EA/EMP/reports/lbnl-3276e.pdf .

[5] *See* D. 08-02-034 at 11 and pages 34 to 36, and at page 38 (Conclusion of Law No. 2).

A: Yes, it has. In the Phase 2 settlement of the last SCE GRC (A. 08-03-002), the Commission also took an important step to provide rates with lower demand charges for large C&I customers who install distributed generation. The SCE settlement created a Rate Option R under SCE's schedules GS-2, TOU-GS-3, and TOU-8, applicable to C&I customers with peak demands from 20 kW to 4 MW who install renewable distributed generation capable of serving at least 15% of their peak demand. Like SCE's DG-R tariff, the SCE Option R rates recover all generation-related capacity costs through energy charges. Option R rates also reduce the distribution component of the facilities-related non-coincident demand charge by 50%. The remaining distribution costs removed from the facilities-related non-coincident demand charge are recovered through a flat energy charge. The Commission approved the SCE settlement in D. 09-08-028.

In SCE's current GRC Phase 2 case, A. 11-06-007, SCE has presented a study of solar customers' contribution to distribution and generation system peaks and the effect of such contributions on rate design. The SCE study cost-justifies its Option R rates, and SCE has proposed to continue to offer Option R rates at least through this GRC cycle. I discuss the SCE Option R study in more detail in Section IV below.

In PG&E's recent Phase 2 case, A. 10-03-014, the Solar Alliance also proposed that PG&E implement Option R rates for its large commercial customers. PG&E and other parties opposed this proposal, contending that this rate option would shift costs to other commercial customers who do not install solar. The Solar Alliance showed that this concern is misplaced, and that Option R rates best represent the costs that solar customers impose on the system. In its order in that case, D. 11-12-053, the Commission determined that "additional study is warranted in a subsequent proceeding examining the demand charges in the E-19 and E-20 tariffs, and the extent to which those demand charges may penalize customers with erratic loads by overcharging them for their contributions to systems peaks." The Commission directed PG&E to provide a study in

its next electric rate design window proceeding that evaluates "whether an Option R rate for E-19 and E-20 customers that shifts a portion of generation and distribution demand charges to TOU energy charges may more appropriately recover capacity-related costs from customers with on-site solar generation facilities."[6]

SEIA recognizes that the prior SDG&E and SCE settlements concerning Schedule DG-R and Option R do not establish precedents for this case. Nonetheless, they do provide examples of rates that comply with the intent of SB 1 to provide the "maximum incentive for ratepayers to install solar energy systems."

III. SDG&E'S PROPOSAL TO RESTRUCTURE ITS SCHEDULE DR RESIDENTIAL RATE

Q: Please describe how the usage-based, tiered residential rates of the IOUs have been restructured in recent years.

A: In 2001, the Commission adopted a residential rate design for the IOUs that featured an inverted block rate design with five usage tiers. As a result of AB 1x, the rates for the first two tiers were frozen from 2000 through 2009, and all residential rate increases in that decade were focused on the rates in Tiers 3 through 5. The passage of SB 695 in 2009 allowed limited annual increases to the Tier 1 and 2 rates, beginning in 2010.

In A. 10-02-029, PG&E proposed changes to its Tier 3-5 rates designed to provide rate relief to high-usage customers, particularly those in the Central Valley.[7] In D. 10-05-051, the Commission approved a Joint Settlement among PG&E, DRA and

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[6] D. 11-12-053, at 28.

[7] PG&E's testimony in A. 10-02-029 provides a thorough summary of the history of residential rate design since 2000 and describes the constraints that AB 1x and AB 695 have imposed on the design of these rates. This testimony is available at http://docs.cpuc.ca.gov/efile/A/114314.pdf .

TURN which combined Tiers 4 and 5 into a single tier, thus eliminating Tier 5. In PG&E's last GRC Phase 2 (A. 10-03-014), PG&E continued to propose changes to its residential rate design, including the following:

- Implementation of a $3.00 per month customer charge and elimination of the existing PG&E minimum bill. This is the same proposal that SDG&E has made in this case, except that PG&E did not propose to adjust the Tier 1 baseline rate downward by the amount of customer charge revenues, as SDG&E has suggested in this case.[8]

- Elimination of Tier 4 and 5 rates, the two most expensive residential rate tiers, which applied to residential usage in excess of 200% of baseline quantities. This was essentially the same proposal for a three-tier rate design that SDG&E has made in this case

PG&E also proposed a new Tier 3 rate for its CARE rates for low-income customers.[9] PG&E argued that the purpose of these changes was to continue to reduce high bills experienced by some high-usage customers in the Central Valley, particularly during hot summer months when demand peaks on the PG&E system. PG&E also contended that its upper tier rates were well above its cost of service, and thus that reducing these rates would better align its residential rates with its cost of service.[10]

A wide range of parties – from consumer groups (DRA and TURN) to representatives of low-income and disabled communities (Greenlining and the Disability Rights Advocates) to renewable energy advocates (Solar Alliance and Vote Solar) to environmental groups (Sierra Club) – opposed most of PG&E's proposed changes. These parties presented evidence of the adverse impacts of PG&E's changes on low-income customers, emphasizing the hardships of rate increases on such customers during a difficult economy. They also argued that substantial reductions in upper-tier rates would impact adversely the state's important policy goals to encourage efficient energy

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[8] A. 10-03-014, PG&E Testimony (Exhibit PG&E-8), at pages 3-3 to 3-13.

[9] *Ibid*., pages 3-21 to 3-23.

use and the adoption of renewable DG resources.[11]

Q: What changes in PG&E's residential rates did the Commission adopt in D. 11-05-047?

A: The Commission's final decision in the PG&E GRC took a balanced approach to PG&E's residential rate design, adopting several further measures to reduce upper tier rates, but by no means all of PG&E's proposals. In adopting this balanced approach, the Commission recognized as follows:

> In evaluating PG&E's proposals, we weigh and balance countervailing goals. We recognize, on the one hand, the importance of moving toward rates designed in relation to the costs of service. This concern becomes more pronounced in view of the large imbalance between upper versus lower-tiered rates over the past decade.
>
> On the other hand, we recognize the importance of avoiding rate shock and keeping essential energy needs affordable, particularly for low-income households. California law requires that retail electric service remains affordable [citing P.U. Code Section 382(b)].
>
> Our obligation to maintain affordable rates must be addressed in the context of California's ongoing economic crisis, high unemployment rates, and rising income inequality. Affordable electricity prices make it easier for poor Californians to pay their energy bills and maintain some degree of comfort and safety….
>
> While we recognize the economic difficulties particularly facing low income households, we are also concerned that higher-usage customers bear a disproportionate burden of cost subsidies. For almost two decades, CARE rates capped *[sic]* while the consumer price index has increased by approximately 51 percent. Thus, CARE customers' bills have declined in real terms by a significant amount….
>
> … By moving toward rate levels that align more closely with costs, rate levels will necessarily increase for the most economically vulnerable customers. Yet, because these rate imbalances developed over a period of several years, we cannot immediately rectify all such imbalances without risking undue rate shock, particularly for low-income households. In this regard, we decline to approve *all* of PG&E's proposed rate changes. Instead, our adopted rate design changes produce an appropriate balancing of interests while keeping overall rate levels reasonably affordable.

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[10] *Ibid*., pages 3-3 to 3-4

[11] D. 11-05-047, at 10-12.

> Another important criterion for rate design is to encourage energy efficiency and use of renewable resources consistent with the Commission's Energy Action Plan. Thus, our adopted rate design measures preserve price signals that promote achievement of energy efficiency and related energy resource goals.[12]

Q: From what perspective should the Commission review SDG&E's new residential rate design proposals in this case?

A: In this case, the Commission should use the same balanced approach that it adopted in the PG&E case. The Commission must consider more than just the impact on SDG&E's high-usage customers, and should recognize the need to make measured, incremental changes to bring SDG&E's rates closer to its cost of service. The Commission also should review SDG&E's proposals in light of the priorities set forth in the state's "loading order" for electric resources. The state's first priority is to encourage energy efficiency; the second is to stimulate the development of renewable generation, including on-site distributed generation such as solar PV. The usage-based, tiered residential rate structure that has been in place since 2001 has advanced both of these top priorities, by sending strong price signals to high-usage customers to reduce their usage and to consider installing on-site renewable generation (principally solar PV) that will reduce or eliminate the customer's marginal, most expensive energy use. As exemplified by D. 11-05-047, the Commission must balance carefully whether California's leadership in energy efficiency and solar development might be threatened by the additional rate design changes that SDG&E is proposing, particularly since one of the primary beneficiaries of these changes are those residential customers who use the most energy. Furthermore, as discussed further below, SDG&E's upper tier rates already are well below PG&E's and are designed in a way that is close to the policies adopted in D. 11-05-047. Finally, SDG&E presents no evidence that it has had the same problems that PG&E experienced in 2009 with vociferous customer complaints about high summer bills in hot climate zones.

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[12] *Ibid.*, at pages 15-18.

Second, the Commission should evaluate the impacts of SDG&E's proposed changes on all Schedule DR ratepayers, including low-income and disabled customers and those in cooler, coastal climate zones who do not use as much energy as those in the warmer inland portions of SDG&E's service territory. SEIA notes that DRA's testimony highlights the significant impacts of SDG&E's proposal on lower-usage customers, particularly on those using less than baseline quantities. DRA opposes SDG&E's customer charge and three-tier proposals, for example, and presents examples of the adverse bill impacts of SDG&E's proposals on both CARE and non-CARE residential customers.[13]

SEIA observes that SDG&E's current Schedule DR rate design is largely consistent with the policies adopted in D. 11-05-047, the most recent fully-litigated proceeding on residential rate design. SDG&E's Schedule DR rate design already has four tiers, with the top three tiers separated by just 2 cents per kWh. Further, as shown in **Table 1** below, SDG&E's current Tiers 3 and 4 residential rates already are well below those adopted for PG&E in D. 11-05-047.[14] As a result, the Commission must consider the extent to which additional major reductions in SDG&E's upper tier rates are necessary.

[13] DRA Testimony, at pages 5-4 to 5-16, especially 5-7 to 5-8 and 5-10 to 5-11.

[14] The SDG&E Tier 3 and 4 rates shown in Table 1 are the simple average of summer and winter rates.

Table 1: *Current PG&E and SDG&E Tiered Residential Rates*

Rate Tier	PG&E Schedule E-1 (Current)	SDG&E Schedule DR (Current)
Tier 1	$0.1285	$0.1433
Tier 2	$0.1460	$0.1658
Tier 3	$0.2994	$0.2483
Tier 4	$0.3394	$0.2683

Q: Does SEIA have a recommendation for the design of the SDG&E Schedule DR rate?

A: Yes. SEIA recommends that SDG&E should retain its existing Schedule DR rate design, as that rate design is similar to the PG&E non-CARE residential rate design adopted in D. 11-05-047. In SDG&E's existing Schedule DR rate design, there is no customer charge, and the differential between the Tier 3 and Tier 4 rates is maintained at two cents per kWh. **Table 2** shows SEIA's proposed rates, and compares them to SDG&E's proposals as set forth in SDG&E's updated February 2012 testimony and to DRA's proposal. SEIA's proposed rates use SDG&E's proposed revenue allocation, but SEIA emphasizes that it takes no position on revenue allocation issues. SEIA notes that its proposed Tier 3-4 rates for SDG&E would be below the PG&E Tier 3-4 rates approved in D. 11-05-047.

Table 2: *Proposed SDG&E Schedule DR Rates*

Rate Tier	SDG&E	DRA	SEIA
Customer Charge	$3.00	*n/a*	*n/a*
Summer			
Tier 1	$0.1328	$0.1433	$0.1433
Tier 2	$0.1658	$0.1658	$0.1658
Tier 3	$0.2675	$0.2327	$0.2706
Tier 4	$0.2675	$0.2527	$0.2906
Winter			
Tier 1	$0.1328	$0.1433	$0.1433
Tier 2	$0.1658	$0.1658	$0.1658
Tier 3	$0.2329	$0.2022	$0.2360
Tier 4	$0.2329	$0.2222	$0.2560

Q: Please comment on the role of a multi-tiered, usage-based residential rate design in stimulating the development of a vibrant market for solar PV in California.

A: It is not surprising that the inverted block rate design with multiple tiers has been an important factor in the strong growth of the residential solar market in California. Data from the CPUC's 2010 report on net metering shows that 88% of residential solar customers had consumption in Tiers 3, 4, or 5 before installing solar.[15] The existing top tier rates often are criticized for being far above the utilities' marginal costs. This is not necessarily true: based on SDG&E's marginal cost proposal, its cost-based residential time-of-use rate for the summer on-peak period is $0.34 per kWh.[16] This is $0.09 per kWh **above** SDG&E's proposed highest, Tier 3-4 summer rate under Schedule DR. It is important to remember that a fundamental purpose of inverted-block rates is to act as a proxy for TOU rates for customers who do not have TOU-capable meters or who have

[15] The CPUC's 2010 Net Energy Metering Report can be found at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf.

[16] Based on SDG&E's DR-SES rate design.

not made the transition to TOU rates. Thus, it is important that the top tiers of inverted block rates should signal to customers the costs of their marginal usage, which should be assumed to occur during the peak period. SDG&E's proposed rates do not come as close to accomplishing this important goal as those that SEIA proposes.

Ultimately, SEIA expects that most residential solar customers will choose to take service under TOU rates; indeed, as discussed above, the LBNL NEM study concludes that current residential solar customers whose systems serve most of their loads would be better off under TOU rates. However, until customers have a better understanding of both the utility's TOU rate structures and the daily profile of their own usage, a significant fraction of residential solar customers will be served under the Schedule DR tariff. To avoid adverse, disruptive impacts on the solar market, the Commission should exercise restraint in making changes to the existing residential rate design. As noted above, the experience at the outset of the CSI program of requiring residential solar customers to take service under TOU rates should be a cautionary tale for how the solar market can be disrupted by too-rapid changes in residential rate design.

Q: Has SDG&E evaluated the impact of its proposed rate design changes in terms of maintaining a strong incentive for customers to conserve energy?

A: No. SDG&E does not appear to have evaluated how its proposals might impact energy use in its service territory.

Q: SDG&E's proposal to consolidate its Tiers 3 and 4 into a single tier is intended to simplify its residential rate structure, allegedly in preparation for greater use of TOU rates.[17] Please comment on this rationale.

A: SEIA recognizes that the California utilities' residential TOU rates that combine both time-of-use periods and usage blocks can be very complicated and difficult for customers

[17] SDG&E Testimony of Cynthia Fang, at page CF-24, lines 13-15.

to understand. However, this argues for simplifying residential TOU rates, not necessarily simplifying the non-TOU rates which are much less complex. For example, SCE has greatly simplified its residential TOU rate (Schedule TOU-D-T) by moving to the use of a simple on- / off-peak TOU structure and by combining its Tiers 1/2 and Tiers 3/4 rates. This results in just four different residential TOU rates that a customer must understand (on- and off-peak, Tier 1/2 and Tier 3/4). If SDG&E wants to simplify its residential rates in preparation for greater use of TOU rates, as it professes, SEIA suggests that SDG&E just simplify its residential TOU rate directly as SCE has done. SEIA believes that SDG&E's proposal to move its non-TOU Schedule DR rate from a four-tier rate to a three-tier structure will not result in a meaningful simplification of its rates, and will unnecessarily dilute the price signal in SDG&E's upper tier rates that both encourages customers to conserve or and consider DG investments.

Q: Why did the Commission reject PG&E's proposal in A. 10-03-014 to consolidate its Tier 3 and 4 rates?

A: The Commission stated clearly that consolidating Tiers 3 and 4 would reduce the signal for high-usage customers to conserve and could slow progress toward meeting the CSI's goals of creating a stand-alone solar PV market:

> If Tier 4 were entirely eliminated, there would be no rate incentive to conserve for usage beyond 200 percent of baseline. Entirely eliminating Tier 4 could impede progress toward achieving the CSI goal of creating a self-sustaining residential solar PV market. By promoting the market for residential PV, we help to advance the state's loading order and meet AB 32 greenhouse gas emission reduction goals.[18]

Q: Has SDG&E provided any evidence of significant complaints from high-usage ratepayers about its Schedule DR rate structure?

A: No. As a result, the Commission should proceed carefully in this case before making further changes to SDG&E's Schedule DR rate structure. The Commission has recently

[18] D. 11-05-047, at 48.

examined its residential rate design policies in detail, and in D. 11-05-047 established policies that, when applied to SDG&E's system, would produce the rates that SEIA has recommended in this case.

IV. PRINCIPLES FOR A TIME-VARIANT TARIFF UNDER SB 1

Q: What are the key principles that should guide the Commission's design of time-variant tariffs that comply with SB 1?

A: Based on P.U. Code Section 2851(a)(4), the key principles for the design of such TOU tariffs are the following:

1. The tariff should create the maximum incentive for ratepayers to install solar systems whose peak production coincides with California's peak electricity demands.

2. The tariff should assure that ratepayers receive due value for their contribution to the purchase of solar energy systems.

3. Customers with solar energy systems should continue to have an incentive to use electricity efficiently.

Generally, these principles will be satisfied if the tariff's rates in each TOU period are designed to reflect, to the maximum extent possible, the costs of utility service that are caused by consumption in that time period. TOU rates that closely reflect variations in cost causation over the course of a day, week, or season will provide the maximum incentive for PV systems to produce power when needed. Rates based on the utility's marginal costs in each time period will ensure that all ratepayers receive due value for the costs that PV production avoids. TOU rates that reflect costs and that are simple and understandable will send the right price signals to encourage solar customers to use electricity efficiently.

Q: **Please discuss the value that participating ratepayers should receive in return for**

the capital that they contribute to the purchase of their systems.

A: These ratepayers should receive due value for the costs that they allow the utility to avoid through their generation of valuable on-peak electricity. This requires careful consideration of the variability of solar generation. Most important, the time-variant rates applicable to solar customers should be structured, to the greatest extent possible, as volumetric, $ per kWh energy charges, without the use of demand charges. If TOU rates include significant demand charges, solar customers may not be compensated for costs that their on-site generation avoids. For example, a cloudy, low-demand day with low PV output may cause a solar customer to incur a significant demand charge for the entire month, and thus will fail to recognize that the same customer contributed significant peaking generation on the hot, sunny, high demand days of that same month (and thus avoided significant capacity-related costs). It is also crucial to recognize that the aggregate capacity of many geographically-dispersed renewable generators, even if their source of motive power is intermittent solar or wind resources, will exceed the sum of their individual capacity contributions.

The Commission has faced this problem before – how to reflect the fact that the aggregate generation from many variable sources allows the utility to avoid capacity-related costs. For example, in setting avoided cost prices for intermittent renewable generation from solar and wind qualifying facilities (QFs), the Commission has recognized since the early 1980s[19] that the aggregate generation of these intermittent resources allows the utilities to avoid the costs of generating capacity, and has paid generators such avoided capacity costs on a volumetric basis through the as-delivered capacity prices available to solar and wind QFs. Much more recently, the Commission has faced the issue of how to value the capacity provided by intermittent wind and solar resources when it established its new resource adequacy (RA) requirements. In D. 09-06-028, the Commission adopted an RA "counting rule" based on the output of the solar

[19] D. 82-01-103, at 30-48.

generator that is exceeded in 70% of the peak hours of the month. The Commission also adopted an upward adjustment to the 70% exceedance value for an individual wind or solar facility that is based on the 70% exceedance metric for the aggregate statewide production from wind and solar facilities. The RA value of a solar PV unit is typically about 60% of its nameplate generating capacity, which is also the typical summer on-peak capacity factor for such a unit.[20] Thus, the Commission has recognized that the capacity value of solar should be calculated from its output across a relatively broad range of peak hours, and should consider the aggregate production from all such intermittent resources.[21] Thus, the Commission has a long-established principle that solar generation allows the utility to avoid capacity-related costs on a volumetric basis. The TOU rates available to solar customers need to be structured to allow customers who install solar generation to offset such costs on a volumetric basis.

An example can help to illustrate this point. Assume that a commercial solar customer has a summer on-peak demand of 100 kW and installs a west-facing solar system with a capacity of 50 kW. Also assume that the system produces 30 kW on average across the weekday on-peak hours of the month (i.e. a 60% capacity factor), and also has an RA value of 30 kW. However, the solar unit produces just 10 kW during some 15-minute intervals on a few cooler, overcast days. To make the math easy, we assume 100 on-peak hours per month. The utility's cost of generating capacity is $25 per kW-month ($150 per kW-year over SDG&E's six summer months), and this cost is driven by demand on hot summer days. If these generating capacity costs are recovered through a demand charge, the solar customer's maximum monthly on-peak demand will

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[20] SEIA has used the National Renewable Energy Laboratory's standard PVWATTS calculator and the Commission's RA counting rule for solar PV to determine an RA value of 59% of nameplate for a representative PV system located in SDG&E's service territory; this unit has a 62% capacity factor over SDG&E's summer on-peak period.

[21] This method replaced the initial counting rule for wind and solar adopted in Decision 04-10-035. The initial rule used the average output from solar and wind facilities over the summer on-peak period as the basis for the capacity contribution of wind and solar to meeting RA requirements. D. 04-10-035, at 24-25, and D. 05-10-042, at 71.

be 90 kW (as a result of the 15-minute intervals on the cloudy days) and the solar customer will pay $2,250 per month in generating capacity charges, just $250 less than what he would pay without solar. This tells the customer that his system avoids just $250 in generating capacity costs. The reality is that the customer's generation on peak days will avoid $750 in capacity costs (the output of 30 kW on sunny days times $25 per kW-month). Thus, the demand charge structure undervalues the solar customer's actual contribution to reducing both peak demands and the utility's generation capacity costs. In contrast, assume that generating capacity costs are recovered through a volumetric $ per kWh on-peak rate of $0.25 per kWh ($25 per kW-month divided by an assumed 100 peak hours). Because the customer produces 3,000 kWh of on-peak generation each month (30 kW times 100 hours), under a volumetric rate structure the solar customer will be able to reduce his bill by the correct $750 in generating capacity costs that are avoided by the 30 kW of peak day generation which the unit provides.

Q: Have there been any studies on the impact of demand charges, and of rate structures generally, on the value of PV systems for commercial customers?

A: Yes. In July 2007, LBNL released a study on the impact of various commercial rate designs on the economic value of PV systems in California.[22] This study used data from 24 commercial PV customers in California to calculate the economic value of PV systems under a number of existing TOU rate designs offered by SDG&E, PG&E, SCE, the Sacramento Municipal Utility District, and the Los Angeles Department of Water and Power. The study looked at PV systems that provide 2% or 75% of the customer's electricity requirements. The LBNL researchers concluded that, particularly for the larger PV systems that offset 75% of the customer's usage, the solar output may not result in a significant reduction in the customer's demand charges. In these cases, when

[22] Ryan Wiser, Andrew Mills, Galen Barbose, and William Golove, "The Impact of Retail Rate Structures on the Economics of Commercial Photovoltaic Systems in California" (Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, July 2007), available at http://eetd.lbl.gov/EA/EMP. I refer to this study hereafter as "the LBNL Study."

the PV system serves a large portion of the customer's load, the customer's demand charges are driven not by the customer's load profile, but by periods when solar production is low.[23] The conclusion to be drawn from the LBNL work is that utility rate structures that emphasize cost recovery through demand charges do not accurately reflect the costs that customers avoid through the installation of solar generation.

Q: Did the LBNL Study examine the impact on solar customers of the design of SDG&E's commercial rates?

A: Yes, it did. The study compared the savings that SDG&E's commercial customers can realize from installing solar PV systems under the utility's primary commercial and industrial (C&I) rate schedules:

- A6-TOU
- AL-TOU

The LBNL researchers show that SCE's Option A rates, and other schedules with zero or relatively small demand charge components (such as the PG&E A-6 rate), produce roughly similar savings in $ per kWh regardless of the size of the solar system, that is regardless of whether the solar system offsets 2% or 75% of the customer's loads. This is what one would expect, given that solar units all should produce relatively similar avoided generation costs in terms of avoided $ per kWh. In contrast, the rates with larger demand charges (such as SDG&E's A6-TOU and AL-TOU) result in significantly smaller savings, expressed in $ per kWh, when customers attempt to serve 75% of their loads with solar, compared to the 2% solar cases.[24] These results show how demand charges can penalize solar customers, particularly solar customers with larger systems, by undervaluing solar customers' avoided generation costs.

Q: Is it important that customers should have the option to select either the SB 1-

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[23] *See* LBNL Study, at pages vi, 21-22, and 32.

[24] *Ibid.*, Figures ES-1 and 13.

compliant TOU tariff or an existing TOU rate schedule for which they qualify?

A: Yes. Customer demand profiles vary widely, and solar installations may offset anywhere from a few percent to 100% of a customer's load. For example, the use of volumetric charges in place of demand charges is particularly important for solar customers whose systems supply a significant share of their usage. The Commission's goal should be to remove the barriers to the use of solar to supply the major share of a customer's load; for this reason, the implementation of an SB 1-compliant TOU tariff is critical. However, it is difficult to design a TOU tariff that will provide the maximum incentive to install solar in all cases.[25] As a result, solar customers should retain the option to choose any TOU rate schedule for which they qualify, particularly until the utilities, the Commission, and the solar industry gain additional experience with customer response to the increased availability of TOU meters and the new emphasis on dynamic pricing.

Q: Do TOU rates generally provide customers with incentives to use electricity more efficiently?

A: Yes. TOU rates that accurately reflect the utility's time-variant marginal costs will result in the more efficient use of electricity than flat rates that do not vary with the time of day. It is important to recognize that, at the margin, the price signal of TOU rates is maintained even if a customer installs solar to offset all of its on-peak usage. For example, even though my own west-facing PV system produces far more power than my home consumes during PG&E's on-peak period, I retain a strong incentive to shift my electric usage out of the summer on-peak period – if I do not run appliances between

[25] For example, the LBNL Study examined whether the economics of solar were improved when commercial customers had the option to choose the most favorable TOU rate. The LBNL researchers concluded that, for PV systems that supply more than 50% of a customer's load, a "PV-friendly" tariff with none or minimal demand charges (i.e. an SB 1 compliant tariff such as the PG&E A-6 rate) almost always will be the preferred choice. However, at low percentages of PV penetration, other tariff options often were more favorable. Thus, the option to choose an existing TOU rate schedule or the SB 1-compliant rate is particularly important for smaller solar systems (relative to load). *Ibid.*, at xviii and 45-52.

noon and 6 p.m., I send additional solar kWhs out to the grid, earning additional net metering credits at the PG&E E-7 summer on-peak rate of about $0.30 per kWh. Then I pay $0.10 per kWh when I run appliances in the off-peak hours of the evening, morning, or on weekends. Thus, even as a solar customer, I continue to see the strong TOU price signal of PG&E's E-7 rate.

Q: Is it important for TOU price signals to be simple and understandable to customers?

A: Absolutely. Customers will be able to use electricity most efficiently only if they understand and can take actions based on TOU price signals. This strongly favors TOU rates set on a $ per kWh basis, without demand charges, even for larger commercial customers.

Q: Is the need for simple, volumetric TOU rate structures particularly important for commercial customers that install solar?

A: Yes. As I noted above, the price signals of TOU rates set on a volumetric, energy basis are preserved even if the customer installs solar and produces a variable amount of solar generation. This is not necessarily the case with commercial rates that include demand charges.

If a commercial customer installs solar, the demand charge that the customer faces will be based on its maximum net consumption from the grid in any 15-minute interval. Due to the natural variability of solar generation, it is difficult for commercial solar customers to monitor, anticipate, or control their net kW demand for grid power. The LBNL Study shows clearly that it is a challenge for commercial solar customers to realize demand charge savings, unless their solar system serves just a small portion of their overall usage.

Q: Please provide an example of a simple, all-volumetric TOU rate for commercial customers.

A: PG&E's A-6 rate is an example of a small commercial TOU rate that meets the criteria set forth in Section 2851(a)(4) of SB 1. The A-6 rate generally has applied to medium light & power customers with peak demands less than 500 kW. The PG&E A-6 rate is an all-volumetric TOU rate, with the exception of a modest customer charge. The rate recovers five-sixths (83.3%) of generation capacity costs through the summer on-peak rate, with the rest collected in the summer partial peak rate. Distribution costs are recovered 60% from summer rates, 40% from winter. The TOU differentiation of A-6 distribution energy charges uses a 2.5 to 1 to 0.5 on-peak to partial-peak to off-peak ratio within the summer season, and 1.5 to 1 partial-peak to off-peak ratio within the winter season. As a result, the A-6 rate reflects the fact that summer on-peak usage is a key driver of capacity-related costs, for both generation and distribution capacity, and provides a strong incentive for solar customers to maximize summer on-peak generation. The rate avoids the distortion of demand charges and thus more accurately reflects the costs that solar customers allow the utilities to avoid. The A-6 rate provides clear signals to commercial customers concerning the cost of electric usage in each TOU period, and thus maintains a strong incentive for A-6 solar customers to use electricity efficiently. The LBNL study shows that, among the principal C&I rates in California, PG&E's A-6 rate consistently provides among the highest savings for solar customers.[26]

Q: Are you aware of any detailed cost studies that have demonstrated that DG customers impose fewer demand-related distribution costs on a utility, such that the distribution rates for DG customers should be structured with reduced demand charges?

A: Yes. SCE has studied this question in the cost study that it prepared for its current GRC Phase 2 case (A. 11-06-007) justifying the continuance of its Option R rates for C&I

[26] *See* Figures 8, 9, and 11 of the LBNL Study.

customers who install solar PV systems. In this study, SCE compared the coincident and non-coincident peak demands of 80 C&I customers after installing PV to (1) their coincident and non-coincident peak demands before installing PV and (2) the coincident and non-coincident peak demands of the general population of similar C&I customers. SCE found that PV installations resulted in a substantial drop in the coincident peak demands of these C&I customers. In particular, at the time of the system peak the coincident peak demands of solar customers were 38 percent lower than the coincident peak demands of the general population of C&I customers and 39 percent lower than the same customers' pre-solar coincident demand.[27] In addition, SCE uses a metric called the Effective Demand Factor (EDF) to measure a customer's contribution to distribution system peaks. SDG&E proposes in this case to move to the use of a similar metric.[28] SCE's study found that the EDFs of solar customers were 32% lower than those of the general population of similar customers, and that these solar customers also contribute 24% less to transmission system peak demands.[29] These results show that solar customers impose lower demands on the T&D system than standard customers, and that it is reasonable, on cost causation grounds, to shift a significant share of these customers' T&D costs from demand charges to energy rates, as provided in SCE's Option R rates and in SDG&E Schedule DG-R. Based on this work, SCE has proposed to continue its Option R rates with reduced T&D demand charges for this three-year GRC cycle.[30]

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[27] Looking at coincident monthly peaks, the solar customers' peaks were 41% below the monthly coincident peaks of similar customers over the four summer months (June-September). SCE Option R Study, at Table 2. SCE's Option R Study is included as **Attachment RTB-2** to this testimony.

[28] SDG&E Testimony of Ms. Fang, at Attachment I, pages CF-11-I to CF-12-I.

[29] SCE Option R Study, at pages 2, 4, and 5.

[30] A. 11-06-007, SCE Updated Testimony, at Exhibit SCE-04, at pages 68-69.

V. THE DESIGN OF SB 1-COMPLIANT TOU TARIFFS FOR SDG&E

A. The Time-Dependent Allocation of SDG&E's Distribution Costs

Q: SDG&E has proposed to design its C&I rates with 100% of distribution costs recovered through a non-coincident maximum demand charge (NCDC). Does SEIA agree with this aspect of SDG&E's commercial rate design?

A: No. SDG&E's present C&I rate design recovers 60% of distribution costs through NCDCs, and 40% through time-related charges. SDG&E's only justification for this substantial change in its C&I rate design is the following statement by Mr. Yunker:

> When looking at customer-specific, demand-related costs, the measure that most accurately reflects the costs incurred to provide distribution services is non-coincident use, as opposed to use coincident with the system peak demand. This is because circuits peak at different times and circuits are built and maintained based on the energy use of the customers on an individual circuit. Non-coincident use, or a customer's use independent of the timing of other customer's use, is an appropriate way to allocate costs when a cost is not tied to the system peak.[31]

SDG&E does not present any data showing that its distribution costs are driven 100% by C&I customers' non-coincident demand.

Q: Have you looked at data on what drives SDG&E's distribution costs for C&I customers?

A: Yes, I have, and I conclude from that review that SDG&E's distribution costs for C&I loads are driven at least in part by coincident, system peak demand. This is particularly true for the upstream end of SDG&E's distribution system, such as its costs for substations, which are the farthest from customer loads and the closest to the transmission system, and where there is a substantial amount of load diversity. Interestingly, Mr. Yunker's testimony above that non-coincident demand is the sole driver of distribution costs appears to refer only to distribution circuits, and does not mention substations.

Q: Please discuss the data which you have reviewed.

A: First, I observe that SDG&E has calculated its marginal distribution costs, for both distribution circuits and substations, by regressing its distribution investments over time as a function of coincident, system demand on the distribution system, as described in the testimony of Mr. Saxe and as confirmed by SEIA in discovery.[32] If non-coincident demand were the sole driver of distribution costs, one would have expected SDG&E to have established its marginal distribution costs using a regression of distribution investments versus non-coincident demand.

Second, I have analyzed data SDG&E provided on when its distribution circuits and substations peak. This data is from 2008, and is the basis for the effective demand factors (EDFs) that SDG&E has used for distribution revenue allocation. I first isolated those substations and circuits on which a majority of the peak demand is from larger AL-TOU C&I customers. Of these substations, 73% by number and 92% by volume (kW of AL-TOU loads) peak during the summer on-peak hours. This result is not surprising, given that SDG&E's C&I loads tend to peak in the early-to-mid afternoon hours, as shown in the figure on page CY-7 of Mr. Yunkers' testimony.

Third, there is a strong correlation between substation peaks and SDG&E's high load hours. 94% of the utility's annual substation peaks occur in hours when system demand is in the top 10% of the hourly loads for the year, as shown in **Figure 1**.

Q: What conclusions and recommendations do you draw from this data, in terms of how to design rates for SDG&E's medium and large C&I customers?

A: The substation portion of distribution revenues should be allocated to peak-related charges, not to the NCDC. Based on SDG&E's proposed marginal costs, the substation portion of the marginal distribution revenues for medium & large C&I customers is

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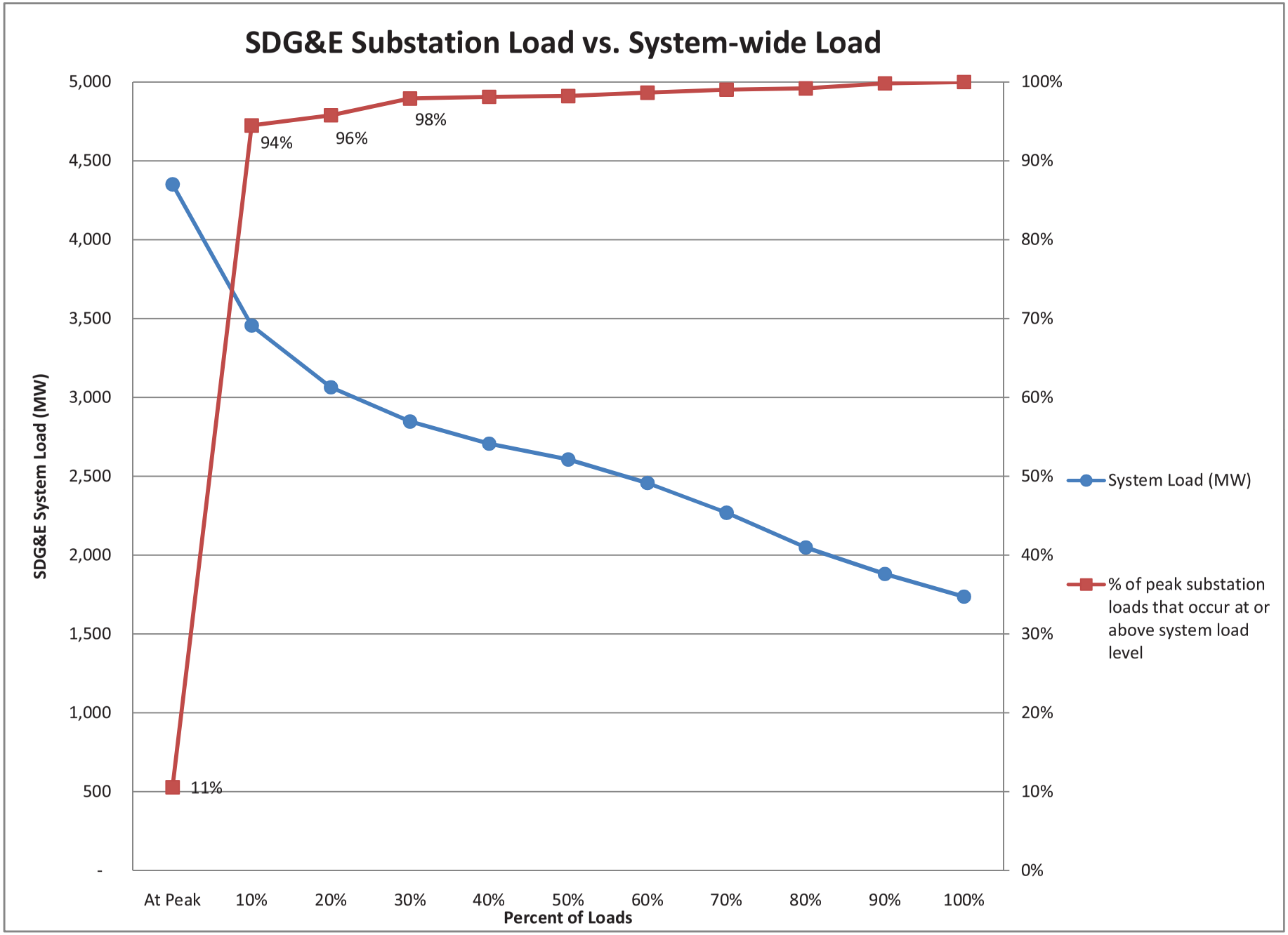
[31] SDG&E Testimony of Chris Yunker, at page CY-6, lines 25-31.

Figure 1



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26.2% of total marginal distribution costs. Accordingly, 26.2% of distribution costs should be allocated to peak demand charges for Schedules AL-TOU and A6-TOU, and to on-peak and mid-peak energy charges for Schedule DG-R. These costs should be allocated between on-peak and mid-peak rates and between summer and winter rates on the basis of SDG&E's relative loss-of-load expectation for each period and season.[33] Schedule DG-R rates should recover these costs through on- and mid-peak energy charges, consistent with the recovery of other peak-related generation / commodity costs through the volumetric rates for this schedule.

Q: Would this distribution rate design for Schedules AL-TOU and A6-TOU be consistent with how distribution rates are designed for other California IOUs?

A: Yes, it would. Like SDG&E, PG&E also has a large, diverse service territory that includes both cooler coastal and mountain areas as well as hotter inland regions. For many years, PG&E has allocated a portion of its distribution system costs on a time-differentiated basis. PG&E computes the marginal distribution costs for primary distribution for each customer class on the basis of each class's contribution to demand in the peak period, through what PG&E calls the Peak Capacity Allocation Factor (PCAF). PG&E's peak demand-related marginal costs for primary distribution filed in its last GRC Phase 2 (A. 10-03-014) are $53.42 per PCAF kW. The utility also computes separate marginal distribution costs for primary distribution for new business and for secondary distribution, using the customer's non-coincident load at the final line transformer (FLT). Based on its last GRC Phase 2 filing, PG&E's marginal distribution costs that are driven by non-coincident, non-peak-related demand total $10.64 per FLT kW for primary distribution new business and for secondary distribution. As a result, 72% of PG&E's system-wide distribution marginal cost revenues are peak-related; the remaining 28% are

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32 *See* SDG&E response to SEIA DR 1, Q10 and SEIA DR 2, Q6, included in **Attachment RTB-3**.

33 Attachment D of Mr. Barker's Chapter 5 testimony for SDG&E provides this loss-of-load-expectation data.

driven by non-coincident demand at the FLT.[34] On this basis, PG&E allocates its peak-related distribution costs on a time-of-use basis, with only the minority of distribution costs that are driven by FLT demand collected using non-TOU rate elements such as non-coincident demand charges or equal energy charges across all time periods.

Q: Are there other examples of the Commission recognizing that a significant share of distribution costs are driven by summer peak demands?

A: Yes. The Commission has adopted models of avoided transmission and distribution (T&D) costs for a variety of purposes, including assessing the cost-effectiveness of energy efficiency and distributed generation programs.[35] These models use a temperature-dependent valuation approach that assigns the bulk of avoided T&D costs to summer peak hours. These models include SDG&E's service territory. Thus, it would be inconsistent for the Commission to adopt energy efficiency and DG programs for SDG&E that assume SDG&E's marginal T&D costs vary by TOU period, yet for SDG&E to design its retail rates under an assumption that there is no such variation.

B. SDG&E's Proposal to Continue Its Schedule DG-R Rate

Q: You have discussed above the problems that demand charges present for solar customers. Has SDG&E developed TOU rate options for commercial solar customers that emphasize volumetric rates which minimize demand charges?

A: Yes, it has. The settlement in the last SDG&E GRC approved the Schedule DG-R rate for C&I customers who install DG. SEIA's predecessor, the Solar Alliance, was a party to that settlement. The testimony of SDG&E's witness Ms. Fang outlines the key elements of the Schedule DG-R rate:

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[34] A. 10-03-014, Exhibit PG&E-2, Chapter 6, Table 6-1.

[35] *See* D. 05-04-24 and D. 09-08-026. The CPUC's avoided cost models for energy efficiency and distributed resources can be found at http://www.ethree.com/public_projects/cpuc4.php .

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

- Schedule DG-R will be designed with a total non-coincident demand charge (D-NCDC) set at 50% of the Schedule AL-TOU NCDC, with the costs removed from the NCDC recovered through a flat distribution volumetric rate.

- Schedule DG-R shall recover all Competition Transition Charge (CTC) costs through energy charges.

- The DG-R rate is applicable to loads below 2 MW, where a DG system serves at least 10% of the customer's peak demand.

Q: Has SDG&E proposed any changes in the DG-R rate design in this case?

A: Yes. In this case, SDG&E proposes 50% reduction in the distribution non-coincident demand charge, instead of the 50% reduction in the total non-coincident demand charge applicable to DG-R customers (considering both transmission and distribution costs) which was adopted in SDG&E's last GRC. As in the present DG-R rate, the costs removed from the distribution NCDC would be recovered through a flat distribution volumetric rate.[36] SEIA has supported similar reductions in distribution NCDCs for PG&E and SCE; as a result, taken in isolation, SEIA does not necessarily oppose this change in the DG-R rate structure. However, in conjunction with the other changes that SDG&E is proposing to its C&I rates – principally recovering 100% of distribution costs through the NCDC, up from the 60% in current rates – plus the significant increase in SDG&E's transmission rates since the last GRC, SDG&E's proposed change to the Schedule DG-R rate structure would greatly increase the NCDC in the DG-R rate, as shown in **Table 3** below. This increase in the DG-R NCDC would result in substantially larger bill increases for DG-R customers compared to similar C&I customers on AL-TOU who have not installed DG. Table 3 shows the past and expected future evolution of SDG&E's transmission and distribution NCDCs in Schedules AL-TOU and DG-R. The top two sections show the NCDCs contained in the 2007 GRC settlement and in

[36] SDG&E Updated Testimony, Exhibit SDG&E-04, at pages 66-69.

SDG&E's present rates. The third section shows the DG-R NCDCs in SDG&E's proposed rates in this case.

Table 3: *NCDCs in SDG&E's Schedules AL-TOU and DG-R ($/kW-month)*

Time Frame	Transmission	Distribution	Total	DG-R NCDC as % of AL-TOU NCDC
1. 2007 GRC Settlement NCDCs				
a. AL-TOU	3.93	6.79	10.72	
b. DG-R	3.93	1.43	5.36	50%
2. Present NCDCs (9/1/11 rates)				
a. AL-TOU	6.05	7.67	13.72	
b. DG-R	6.05	0.86	6.91	50.4%
3. SDG&E Proposed NCDCs				
a. AL-TOU	6.05	11.72	17.77	
b. DG-R	6.05	5.86	11.91	67%
4. SEIA Proposed NCDCs				
a. AL-TOU	6.05	8.66	14.71	
b. DG-R	6.05	1.31	7.36	50%
5. SEIA NCDCs (after FERC case)				
a. AL-TOU	0	8.66	8.66	
b. DG-R	0	4.33	4.33	50%

Q: How does SEIA propose to mitigate these bill impacts on DG-R customers?

A: There are two clear ways to mitigate these bill impacts. First, the Commission should adopt SEIA's proposal to recover no more than 73.8% of SDG&E's distribution costs through NCDCs and the remainder through peak-related energy charges. Second, as discussed further below, SDG&E's plan to ask the FERC to re-design its transmission rates to be based on peak-related charges also will mitigate the overall NCDCs faced by DG-R customers.

Q: Does SEIA support SDG&E's proposal to change its FERC-regulated transmission rate design to move away from the use of NCDCs to recover transmission costs, and to the use of peak-related demand charges, as Ms. Fang discusses on page CF-26 of her testimony?

A: Yes. I agree with Mr. Yunker's statement at page CY-7 of his testimony that transmission system peaks are coincident with system peaks. As a result, transmission rates should be based on peak-related charges, not on NCDCs. The only modification that SEIA recommends in this proposal would be that, for the Schedule DG-R rate, transmission costs should be recovered through on-peak energy charges, consistent with the recovery of other peak-related costs through the volumetric rates for this schedule.

Q: Obviously, it will take some time before new transmission rates can be set, and of course the FERC must approve such rates. In the interim until these rate design changes can be made, are there additional adjustments that SDG&E should make in its DG-R rate?

A: Yes. SDG&E indicates that it "intends to make efforts to coordinate the timing of the implementation of both proposals"[37] (i.e. increasing distribution NCDCs and reducing transmission NCDCs). In this way, SDG&E appears to recognize the burden which its increasing NCDCs impose. To mitigate the bill impacts on DG-R customers, SDG&E should provide an additional reduction in the NCDC of its Schedule DG-R rate until the FERC rate changes are approved, with the associated costs shifted on an equal cents per kWh basis to all Schedule DG-R energy rates. This reduction would result in the total DG-R NCDC being set at 50% of the total AL-TOU NCDC, similar to the current DG-R rate design. This effectively will mitigate demand charge impacts on DG-R customers.

Q: What is the DG-R rate that SEIA proposes?

A: The fourth section of Table 3 shows the NCDCs that would result from SEIA's

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[37] SDG&E Testimony of Ms. Fang, at CF-26.

recommended allocation of distribution costs and its preferred DG-R rate design. The fifth section of Table 3 shows the NCDCs which SEIA anticipates if SDG&E carries through on its proposal to change the design of its FERC transmission rates.

SEIA provides below **Tables 4a and 4b** showing the demand changes and energy rates of SEIA's proposed Schedules DG-R and AL-TOU.

Table 4a: *SEIA Proposed Schedule DG-R Rate Components*

Demand Charges ($/kW)	Transmission	Distribution	Total
Maximum Demand	6.05	1.31	7.36
On-Peak Demand Summer	1.31	-	1.31
On-Peak Demand Winter	0.28	-	0.28
Energy Charges (c/kWh)	On-Peak	Semi-Peak	Off-Peak
Summer (May-October)	36.248	17.020	14.298
Winter (November-April)	12.774	10.399	9.861

Table 4b: *SEIA Proposed Schedule AL-TOU Rate Components*

Demand Charges ($/kW)	Transmission	Distribution	Total
Maximum Demand	6.05	8.66	14.71
On-Peak Demand Summer	1.31	6.48	7.79
On-Peak Demand Winter	0.28	0.17	0.45
Energy Charges (c/kWh)	On-Peak	Semi-Peak	Off-Peak
Summer (May-October)	9.612	8.935	7.009
Winter (November-April)	9.085	7.971	6.437

Note: Rates shown are for secondary voltages.

VI. RECOMMENDED CHANGES TO SDG&E'S MARGINAL COSTS

A. Decrease SDG&E's Marginal Energy Costs

Q: Have you prepared a forecast of SDG&E's marginal energy costs?

A: Yes, I have. SEIA's forecast of SDG&E's marginal energy costs (MECs) is based on a forecast of the average market prices, by TOU period, in the CAISO's SP-15 market zone for calendar years 2013 to 2014. Natural gas and electric market prices have declined further since SDG&E filed this case, and SDG&E's marginal energy costs should be updated to incorporate these market changes.

Q: What natural gas price forecast have you prepared?

A: SEIA's projection of SDG&E's marginal energy costs begins with a forecast of natural gas burnertip prices in 2013 and 2014, based on forward market prices at the Southern California border. We add SDG&E gas transportation costs to these prices, similar to those used in SDG&E's monthly avoided cost postings, to produce a burnertip price forecast for 2013 and 2014. This natural gas price forecast is shown in the following table. The forecast is based upon publicly available data, and reflects forward market prices as of early June, 2012, for natural gas in 2013 and 2014 delivered to the Southern California border at Topock, Arizona.

Table 5: *Natural Gas Price Forecast ($/MMBtu)*

Period	Henry Hub	Basis	Topock	Burnertip
2013	3.42	0.13	3.54	3.91
2014	3.83	0.15	3.98	4.36
Average 2013-2014			3.76	4.13

Q: How did you use this gas price forecast to estimate SP-15 electric market prices in 2013 and 2014?

A: The next step is to multiply the forecast of natural gas prices by a forecast of the market heat rate (MHR) in 2013 – 2014, and then to add variable O&M costs. This results in a forecast of annual average electricity market prices in 2013 – 2014. To obtain a publicly available estimate of the 2012 MHR, SEIA makes use of Southern California Edison's January 2012 Short-run Avoided Cost (SRAC) posting, which contains SCE's estimate of the 2012 Market Heat Rate (MHR) equal to **7,092 Btu per kWh**. This number was calculated by SCE and is based on gas and electric futures market data for 2012 sampled over the trading days in December 2011. It should be noted that the use of this MHR for 2013 and 2014 produces a forecast of SP-15 market prices which excludes the upward impact on electricity market prices that will result from the implementation of a cap and trade market for greenhouse gas (GHG) allowances in 2013 and 2014. SDG&E did not provide an estimate of the 2012 MHR in its avoided cost posting for January 2012, but we note that the SCE and SDG&E MHRs are virtually identical, given that they both are based on the SP-15 market for electricity and the Topock market for natural gas.

Q: How did you develop TOU factors to convert these annual average prices into a forecast of MECs by TOU period?

A: To calculate MECs by TOU period for the SP-15 market, SEIA looked at the TOU profile of day-ahead SP-15 market prices from June 2011 to May 2012, normalized for changes in natural gas prices throughout the 12-month period. This provides a set of TOU factors that can be applied to forecast annual average SP-15 market prices in 2013 and 2014 by TOU period.[38] We show the gas-normalized SP-15 market prices by SDG&E TOU period in the following **Table 6**, including the TOU factors that result from these price profiles.

[38] SDG&E has several different sets of TOU periods. In our analysis we have used the AL-TOU class TOU periods.

Table 6: *June 2011 to May 2012 SP-15 Market Prices by TOU Period & TOU Factors*

		On-Peak	Semi-Peak	Off-Peak	Average
$/MWh	Summer	38.74	29.49	22.84	27.84
	Winter	39.19	33.93	27.26	30.79
	Annual				29.31
TOU Factor	Summer	1.32	1.01	0.78	0.95
	Winter	1.34	1.16	0.93	1.05
	Annual				1.00

Q: What is the forecast of 2012 to 2014 "base" electricity prices excluding the impact of cap and trade?

A: Similar to the methodology employed in Commission Resolution E-4442 adopting the 2011 Market Price Referent (MPR), SEIA assumes that any increases to MHRs from 2012 to 2013 - 2014 will be due to the implementation of a cap and trade market starting in 2013. Thus, electricity market prices in 2013 and 2014 may be modeled as the sum of two price components: an electricity market price that excludes the impact of cap and trade, and an additional component in 2013 and 2014 that accounts for the forecast price of greenhouse gas (GHG) allowances. The first piece is simply the product of the natural gas burnertip price forecast and SDG&E's 2012 MHR, plus a small adder for variable O&M. The following table shows the results of this calculation, by TOU period.

Table 7: *Forecast 2013 to 2014 SP-15 Market Prices Excluding GHG Impacts*

		On-Peak	Semi-Peak	Off-Peak	Average
$/MWh	Summer	42.62	32.45	25.13	30.63
	Winter	43.11	37.33	29.99	33.88
	Annual				32.25
TOU Factor	Summer	1.32	1.01	0.78	0.95
	Winter	1.34	1.16	0.93	1.05
	Annual				1.00

Q: What forecast of GHG allowance prices have you assumed?

A: Resolution E-4442 adopting the 2011 MPR calculates a forecast of greenhouse gas

(GHG) allowance prices based upon the notion that increases in MHRs in years beyond 2012 can be attributed to the implementation of the state's cap & trade program to regulate GHG emissions, featuring a market for GHG allowances. In other words, in addition to the forecast shown above of average electricity market prices in 2013 to 2014, there will be a GHG component of market prices that reflects the cost of GHG allowances for wholesale electric generation. We have made use of the 2011 MPR forecast of GHG allowance prices adopted in Resolution E-4442, as shown in the following table. Allowance prices in $ per metric ton are converted to a gas price adder in $ per MMBtu assuming a conversion rate of 117 lbs of CO_2 per MMBtu of natural gas.

Table 8: 2011 *MPR GHG Allowance Price Forecast*

Year	$/Tonne	$/MMBtu
2012	-	-
2013	16.29	0.86
2014	22.29	1.18

Q: How did you calculate all-in SP-15 market prices that include the impact of GHG allowance prices?

A: We applied SDG&E's 2012 MHR to the sum of forecast 2013 to 2014 natural gas burnertip prices and the GHG allowance price forecast expressed as a gas price. That calculation is shown below. Essentially, it assumes that SDG&E's 2012 MHR will increase in 2013 and 2014 due to the cap & trade market, as shown in **Table 9**.

Table 9: *Annual 2013 to 2014 Marginal Energy Costs Including GHG Component*

Period	Forecast Gas Price ($/MMBtu)	GHG Adder ($.MMBtu)	MHR w/o GHG (Btu/kWh)	MHR with GHG (Btu/kWh)	Variable O&M Adder ($/MWh)	Marginal Energy Cost ($/MWh)
2013	3.91	0.86	7,092	8,659	2.93	36.80
2014	4.36	1.18	7,092	9,018	2.93	42.21
Average	4.13			8,839		39.50

Q: What is your forecast of MECs by TOU period?

A: We apply the June 2011 – May 2012 TOU profile to our forecast of average 2013 and 2014 MECs that includes the impact of GHG allowances. SEIA's marginal energy cost forecast and the corresponding energy TOU factors for SDG&E are summarized in **Table 10** below. While this forecast is based upon 100% publicly available data, we note that we have compared it to confidential June 6, 2012 SP-15 forward market prices for 2013 and 2014, which are within one percent of the forecast we have prepared. SDG&E's and DRA's forecast MECs averaging about 5 cents per kWh., on the other hand, are substantially higher than either our public forecast or recent forward market prices, and thus do not adequately account for the recent data on natural gas and electric market prices.

Table 10: *Forecast 2013-2014 MECs ($/MWh) and TOU Factors*

Season	On-Peak	Semi-Peak	Off-Peak	Average
Summer (May-Oct)	52.21	39.75	30.79	37.53
Winter (Nov-Apr)	52.82	45.73	36.74	41.51
Annual Average				39.50
Summer	1.32	1.01	0.78	0.95
Winter	1.34	1.16	0.93	1.05
Annual				1.00

B. Increase SDG&E's Marginal Generation Capacity Costs

Q: SDG&E bases its marginal generation capacity cost (MGCC) on the annualized fixed costs of a new combustion turbine (CT), less the energy rents that such a unit could earn in the market. SDG&E's witness David Barker calculates a MGCC of $120 per kW-year. In contrast, the Division of Ratepayer Advocates recommends a MGCC of just $100 per kW-year, asserting that SDG&E does not need capacity in

its service territory until 2017. Please comment on these approaches to determining SDG&E's MGCC.

A: California's Renewables Portfolio Standard (RPS) legislation requires SDG&E and the other IOUs to procure, by the end of 2020, at least 33% of their generation from renewable resources meeting RPS eligibility requirements.[39] Today, SDG&E is actively procuring new renewable generation toward this goal, and must meet interim RPS goals between now and 2020.[40] To meet the marginal demand on its system while complying with the RPS statute, SDG&E must incur the cost of additional renewable capacity. New renewable generators pass these capacity-related costs through to SDG&E and its ratepayers by contract. RPS costs are primarily capacity-related, as all RPS-eligible technologies except biomass do not have fuel costs, and are substantially more expensive than CT capacity. SEIA does not believe that the determination of SDG&E's marginal generation capacity costs can ignore the significant renewable capacity costs that SDG&E is incurring today.

Q: How should the calculation of SDG&E's marginal generation capacity costs recognize RPS costs?

A: DRA's testimony claims that the annualized cost of a CT should be discounted in order to reflect its assertion that SDG&E does not need capacity until at least 2017.[41] DRA cites many cases from the 1990s in which the Commission made such adjustments to marginal generation capacity costs to reflect periods when a utility had excess capacity. Times have changed significantly since then, however. Today, the resource adequacy (RA) program continually enforces a 15%-17% reserve margin each year, and the RPS program requires the addition of renewable capacity even if the utility's reserve margin is above the RA reserve margin. As a result of these requirements, there is little chance that

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[39] Public Utilities Code Sections 399.11 - 399.20.

[40] P.U. Code Section 399.15[b][2][A] and [B]. For example, the IOUs must achieve a 25% RPS by 2016.

[41] *See* DRA Testimony, at pages 2-6 to 2-12.

a California utility will be short on capacity for the foreseeable future, as shown by the reserve margins projected in the LTPP case and by the WECC.[42] This does not mean, however, that SDG&E is not and will not be incurring incremental capacity-related costs, particularly for RPS power. In addition, although most of the parties to the LTPP case agreed that the IOUs have no immediate need for fossil capacity, they also agreed that continued study is needed of the future resource requirements associated with integrating 33% renewables and that the work on determining this need should continue in 2012.[43] Thus, there remains the possibility that fossil capacity will be needed in SDG&E's territory for grid security, renewables integration, or local capacity requirements.

The possible need for new capacity to meet local capacity needs in the San Diego area recently has been underscored by the extended outage at the San Onofre Nuclear Generation Station (SONGS), apparently as a result of flaws in the recently-replaced steam generators at that plant. There is the potential for this outage to be prolonged if the steam generators must be replaced or modified, or for the plant's capacity to be significantly de-rated.[44]

DRA's argument that the MGCC should be discounted from a CT might make sense in a world without an RPS requirement and without the RA program. However,

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42 *Ibid.,* at pages 2-7 to 2-9.

43 R. 10-05-006, Motion For Expedited Suspension Of Track 1 Schedule, And For Approval Of Settlement Agreement Between And Among Pacific Gas And Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, The Division Of Ratepayer Advocates, The Utility Reform Network, Green Power Institute, California Large Energy Consumers Association, The California Independent System Operator, The California Wind Energy Association, The California Cogeneration Council, The Sierra Club, Communities For A Better Environment, Pacific Environment, Cogeneration Association Of California, Energy Producers And Users Coalition, Calpine Corporation, Jack Ellis, Genon California North LLC, The Center For Energy Efficiency And Renewable Technologies, The Natural Resource Defense Council, NRG Energy, Inc., The Vote Solar Initiative, And The Western Power Trading Forum, filed August 3, 2011, at page 4.

given that state law and Commission policies have enforced both a 33% RPS and a 15-17% short-term reserve margin, there is no longer much relevance to the idea of discounting marginal generation capacity costs based on today's high reserve margins and on a projection when in the future "traditional" fossil capacity will be "needed." In fact, today, the RPS program is increasing renewable capacity in California and in SDG&E's service territory, at a capacity cost well above the costs of a new CT. This strongly suggests that the full cost of a CT is a conservative proxy for SDG&E's MGCC. The remainder of the RPS capacity costs that SDG&E is incurring today can be considered "renewable energy-related capacity costs" which are incurred to obtain the clean, renewable generation with low or zero variable energy costs.

Finally, SEIA notes that SDG&E also proposes no adjustment to its marginal generation capacity costs based on supply/demand considerations in its market.

For these reasons, SEIA believes that SDG&E's MGCC should be based on the full annualized fixed costs of a new combustion turbine in the 2013-2014 forecast period, similar to the method that SDG&E uses.

Q: Please provide SEIA's recommendation for the determination of the annualized fixed costs of a new combustion turbine in SDG&E's service territory.

A: SEIA suggests two possible approaches. The first is to use a completely independent source – the calculation of the annualized costs of a new CT which the CAISO includes each year in its *Annual Report on Market Issues and Performance (Annual Report).* In the CAISO's 2011 Annual Report, issued in April 2012, the CAISO calculates the annual fixed revenue requirement for a new CT in 2011 to be $211.70 per kW-year, offset by $48.67 per kW-year in net revenues from energy and ancillary service sales in the SP-15

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[44] SONGS Unit 2 will be shut down at least through August and Unit 3 will be off-line for even longer, according to SCE. See http://www.edison.com/pressroom/pr.asp?id=7956; also http://articles.latimes.com/2012/jun/08/local/la-me-0608-san-onofre-20120608 .

market.[45] Thus, the net cost of CT capacity is $163.03 per kW-year in 2011. Escalated to 2013 – 2014, this is $171.30 per kW-year.

The other approach is to use a modified version of SDG&E's calculation. SDG&E's model for combustion turbine (CT) fixed costs annualizes the installed capital costs of a CT using a real economic carrying charge, then adds fixed O&M and other loaders and subtracts the energy rents and ancillary service revenues earned by the CT in the market. The first issue is the type of CT unit to use as the marginal cost of generating capacity. SEIA supports SDG&E's use of an LM6000 as the basis for the marginal cost of generation capacity.

The next issue is the installed cost per kW for LM6000 CT units. SDG&E states that it spent $1,180 per kW in 2006 – 2007 on its own Miramar II LM 6000 CT, which used wet cooling.[46] The CEC's 2009 study of comparative generation costs in California cites a cost of $1,292 per kW in 2009$ for "small," efficient 50 MW CT units with heat rates in the range of 9,300 Btu/kWh (such as LM6000s), using dry cooling.[47] Thus, given that the cost of the SDG&E units may be too low as a result of the wet cooling feature, we use the CEC's 2009 costs, and then escalate them to 2013-2014 dollars at 2% per year. This yields an installed CT cost in 2012 of $1,412 per kW.

We next use SDG&E's method to calculate annualized CT costs. SDG&E's stated fixed O&M costs are $10.80 per kW-year, from CEC data. With respect to energy rents and ancillary service revenues, we use SDG&E's calculations, notwithstanding that

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45 CAISO *Annual Report*, at 47-48. These pages are included in **Attachment RTB-4**.

46 SDG&E Testimony of Mr. Barker, Chapter 5, at page DTB-7.

47 *Comparative Costs of California Central Station Electricity Generation Technologies* (CEC Staff Final Report, January 2010, CEC Publication CEC-200-2009-017-SF), Table 14, at page 54. This CEC report is available at http://www.energy.ca.gov/2009_energypolicy/documents/index.html#082509 .

these revenues may be high given that natural gas prices have continued to decline from 2011 into 2012, thus reducing the energy rents available in the market.

Table 11 presents the details of our revised version of SDG&E's calculation of marginal generating capacity costs, based on new CT costs for the 2013-2014 period.

Table 11: *New CT-based Marginal Generation Capacity Cost (2013$)*

1	Combustion Turbine Installed Cost *(EOY 2013 COD)*	*$/kW*	1,412
2	Real Economic Carrying Charge Rate		10.56%
3	Annualized CT Installed Cost *(line 1 x line 2)*	*$/kW-yr*	149.11
4	Fixed O&M	*$/kW-yr*	17.40
5	General Plant and A&G Loaders *(4.625% of lines 3 and 4)*	*$/kW-yr*	7.70
6	**Incremental Capacity Cost ('13) *(sum of lines 3 and 4)***	***$/kW-yr***	**174.21**
7	*less* Energy Rents and Ancillary Service Revenues	*$/kW-yr*	(31.97)
8	Total CT-based Marginal Generation Capacity Cost ('13)	*$/kW-yr*	142.24
9	**Total CT-based Marginal Generation Capacity Cost (EOY 2013 $)**	***$/kW-yr***	**142.24**

Q: What is SEIA's recommended marginal generation capacity cost for SDG&E?

A: SDG&E's recommended marginal generation capacity costs for SDG&E averages the two approaches described above, resulting in a recommended MGCC of $157 per kW-year in 2013 dollars at the transmission level.

Q: Does this conclude your testimony in this case?

A: Yes, it does.

Attachment RTB-1

Curriculum Vitae of R. Thomas Beach

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has participated actively in most of the major energy policy debates in California, including renewable energy development, the restructuring of the state's gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning California's large independent power community. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of PURPA.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning California's Renewable Portfolio Standard program, including the calculation of the state's Market Price Referent for new renewable generation. He has also worked for the solar industry on the creation of the California Solar Initiative (the Million Solar Roofs), as well as on a wide range of solar issues in other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, electric transmission and interconnection issues, property tax matters, standby rates, QF efficiency standards, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CPUC

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar powerplants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems*.

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

    - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

    - *Development of a community solar program for Xcel Energy.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the New Mexico Independent Power Producers, (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Standby rates for net-metered solar customers, and the cost-effectiveness of net metering.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

Attachment RTB-2

SCE Option R Study

January 19, 2011

Impact of Customers' Solar PV Installations on System Load

Certain customers with solar PV installations are eligible to take service under a new rate option (Option R) that was approved as part of a settlement agreement in Phase 2 of SCE's 2009 GRC. As a condition of settlement, SCE agreed to conduct a study to determine solar customers' contribution to the distribution and generation system peaks and the effect of such contribution on revenue allocation, and then to redesign the distribution facilities-related demand charge to reflect the actual contribution to facilities-related peak demand drivers. The purpose of this study is to evaluate the impact of these solar PV installations on SCE system load using data that are available for TOU-GS-3 customers.[1]

For this study, SCE evaluated TOU-GS-3 customers' non-coincident demand, demand at the time of system peak, percent of usage in the on-peak period, and Effective Demand Factor (EDF[2]). EDF is the ratio of a customer's contribution to the peak load on a transmission or distribution circuit to the customer's annual non-coincident peak demand. In this study EDF is used as a measure of customers' contribution to distribution peak and the non-coincident and coincident peaks are used as measures of solar customers' contribution to generation peak.

As of December 2009, there were 80 TOU-GS-3 accounts with solar PV installations. This evaluation was performed using a two-fold comparison:

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[1] SCE used TOU-GS-3 customers as representatives of all C&I customers with demand above 20 kW. TOU-GS-3 serves customers with load between 200 and 500 kW, customers in this range are considered mid-size C&I customers.

[2] EDFs vary by type of customer and by the voltage level of the circuit. Unlike rate group coincident demand, which is measured for customers within a particular rate group, effective demand takes intergroup diversity into account. See SCE-2 Appendix B for details on calculation of EDF for all the rate groups

1) A comparison of these accounts' load statistics in 2009 with the same load statistics in 2006. We consider the 2006 data to represent usage characteristics prior to solar installation since more than 85% of the TOU-GS-3 PV systems were installed after 2006. This step represents the before and after solar installation comparison.
2) A comparison of these accounts' 2009 load statistics with the load statistics for the entire TOU-GS-3 rate class (population) for the same period.

The following table summarizes the results of our analysis:

Table 1

	Non Coincident Peak Demand (kW/Cust)	Percent Of On-Peak Usage	System Coincident Peak Demand (kW/Cust)	12 kV Effective Demand Factor
Pre-Solar (2006)	314	24.37%	213	
Solar TOU-GS-3 (2009)	308	19.28%	129	0.51
Overall TOU-GS-3 (2009)	307	24.63%	208	0.75

The 2009 average non-coincident peak demand for Solar TOU-GS-3 and for the TOU-GS-3 population are approximately the same, with the population's non-coincident peak demand being 2% lower than the 2006 average non-coincident peak demand for Solar TOU-GS-3. The 2009 summer percent of on-peak usage for Solar TOU-GS-3 is 19.28%, which is significantly lower than their 2006 summer percent of on-peak usage. The system coincident peak demand decreases by 84 kW or 39% after the solar equipment were installed. The EDF which is used to establish the distribution facility-related demand charge for Solar TOU-GS-3 is 32% lower than that of the TOU-GS-3 population.

Figure 1 and 2 show similar results in a graphical format. Figure 1 depicts the load profile for the average TOU-GS-3 solar customer in 2009 (with solar PV systems installed), compared to the 2006 system peak day (prior to installation of solar PV systems). Figure 2 compares the 2009 load profile for the average TOU-GS-3 solar customer with the average TOU-GS-3 rate group. As these graphs show, during the on-peak period (11 AM PST to 5 PM PST), the solar customers' coincident load

(with solar PV systems installed) is approximately 40% lower than the same customers' load during the 2006 system peak day.

Figure 1

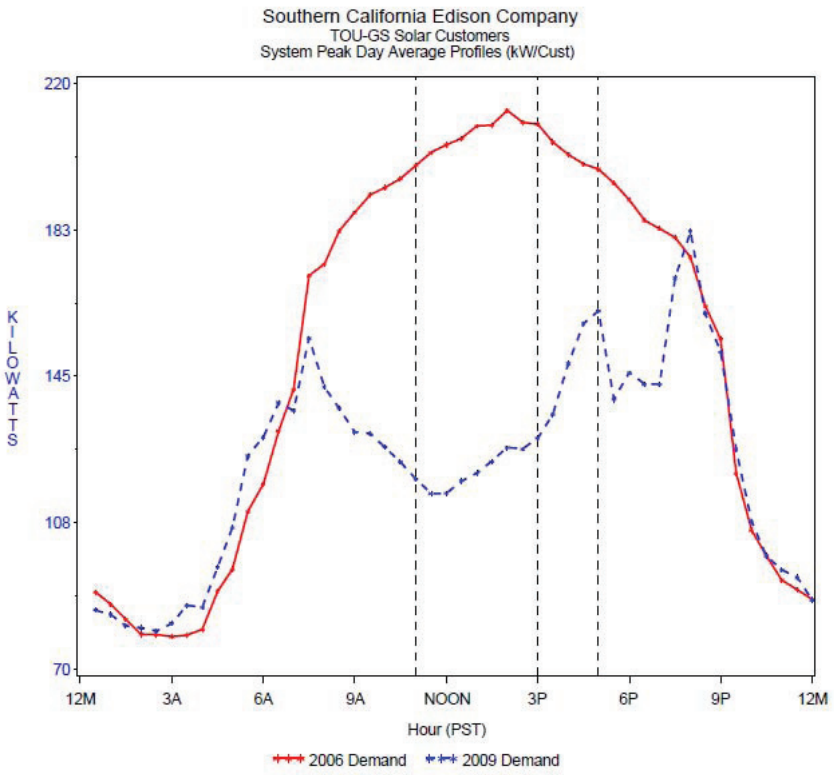

Figure 2

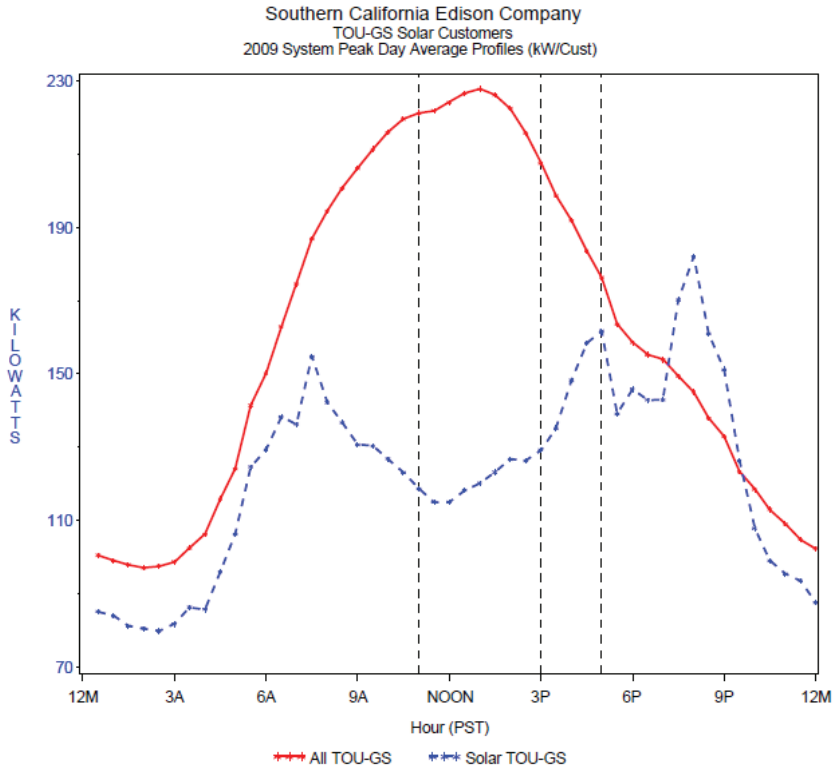

Table 2 compares TOU-GS-3 solar customers' coincident peak demands with the coincident peak demand for TOU-GS-3 population, for each month in 2009. The table shows that the TOU-GS solar customers' sum of 12-monthly peak demands is 24% lower than the sum of 12-monthly peak demands for the population.

Table 2

2009 TOU-GS Solar Load Study
Monthly System Coincident Peak Demand

Date	Peak Time	Total # Of TOU-GS	Number Of Solar	Population Avg. Demand (kW)	Solar Avg. Demand (kW)	Percent Of Change
Tue, Jan 13, 2009	6:00P	8,092	74	144	162	12.59%
Mon, Feb 9, 2009	6:30P	8,068	77	123	137	11.38%
Wed, Mar 18, 2009	7:00P	8,070	77	130	145	11.95%
Tue, Apr 21, 2009	3:30P	8,054	79	182	107	-40.97%
Thu, May 7, 2009	3:00P	8,058	79	186	102	-45.31%
Mon, Jun 29, 2009	2:00P	8,069	79	176	90	-48.47%
Mon, Jul 20, 2009	3:00P	8,043	79	188	113	-39.82%
Thu, Aug 27, 2009	3:30P	8,014	80	194	123	-36.52%
Thu, Sep 3, 2009	3:00P	7,998	80	208	129	-37.74%
Fri, Oct 16, 2009	3:00P	8,008	80	186	113	-39.13%
Mon, Nov 2, 2009	6:00P	8,005	80	146	159	8.57%
Tue, Dec 8, 2009	7:00P	8,005	81	125	126	0.99%
Sum of 12 Monthly Peaks				1,988	1,506	-24.25%

Based on results of this study measuring solar customers' contributions to distribution and transmission peak demands, the Option R rate design will reflect a facility-related demand charge offset of 32% and 24%, respectively for distribution and transmission. The combined facility-related demand charge reduction will only be reflected in the distribution facility-related demand component per the settlement agreement in SCE's 2009 GRC Phase 2, and any resulting revenue shortfall will be recovered through the distribution energy charge on a dollar per kWh basis. As mentioned above, TOU-GS-3 serves as a proxy for all C&I customers above 20 KW. Therefore, SCE will propose the same facility-related demand adjustment be applied to Option R, under schedules GS-2 and TOU-8.

Attachment RTB-3

SDG&E Responses to SEIA Data Responses

SEIA DATA REQUEST NUMBER DRA-01
SDG&E 2012 GRC PHASE 2 A.11-10-002
REQUEST DATED: 05/7/2012
SDG&E RESPONSE DATED: 05/21/2012

Question 2. Please provide the following information on the solar photovoltaic (PV) or other renewable distributed generation (DG) that has been installed (or that has submitted a completed CSI or SGIP application to SDG&E), where the commercial or industrial (C&I) customer installing such generation has (or has not) elected to take service under SDG&E's DG-R rate schedule. A C&I customer should be one whose otherwise applicable rate is one of SDG&E Schedules A, AD, A-TOU, AY-TOU, AL-TOU, or A6-TOU.

a. The number of C&I customers that have installed or have pending applications for solar PV systems and that have elected Schedule DG-R rates, since DG-R rates became available in May 2008.
b. The number of C&I customers that have installed or have pending applications for renewable DG technologies other than solar (e.g. wind or biogas) and that have elected DG-R rates, since DG-R rates became available in May 2008.
c. The number of C&I customers that have installed or have pending applications for solar PV systems or other renewable DG systems, and that have qualified for but have <u>not</u> elected DG-R rates, since DG-R rates became available in May 2008. SDG&E can derive this from the total number of C&I customers that have installed or have pending applications for solar PV systems or other renewable DG systems since DG-R rates became available in May 2008, less the number in the response to part (a) of this question.
d. The total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers who have elected DG-R rates, since DG-R rates became available in May 2008.
e. The total nameplate capacity (in kW or MW) of the renewable DG technologies other than solar (e.g. wind or biogas) installed or applied for by C&I customers who have elected DG-R rates, since DG-R rates became available in May 2008.
f. The total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers who have qualified for but have <u>not</u> elected the DG-R rate, since the DG-R rate became available in May 2008. SDG&E can derive this number from the total nameplate capacity (in kW or MW) of the solar PV systems installed or applied for by C&I customers since DG-R rates became available in May 2008, less the number provided in response to part (d) of this question.
g. The number of DG-R customers and the MW of renewable generating capacity that those customers have installed or applied for, broken down by rate schedule (i.e. SDG&E Schedules A, AD, A-TOU, AY-TOU, AL-TOU, or A6-TOU).

h. The number of DG-R customers and the MW of renewable generating capacity that those customers have installed or applied for, broken down by the year in which the customer elected the DG-R rate (i.e. 2008, 2009, 2010, or 2011 to date).

SDG&E Response 02:

a. 116 customers

b. 7 customers

c. 577 customers

d. 18,470 kW

e. 2,830 kW

f. 51,795 kW

g. All customers on Schedule DG-R take service on Schedule DG-R. For this reason, no customers on DG-R take service on the other non-residential rate schedules identified in the question (e.g., Schedules A, AD, A-TOU, AY-TOU, AL-TOU, and A6-TOU).

h. Please see the table below.

Year	Customers	NEM Nameplate (MW)
2008	46	7.2
2009	10	1.6
2010	25	4.6
2011	29	6.1
2012	13	1.8
Total	**123**	**21.3**

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SDG&E 2012 GRC PHASE 2 A.11-10-002
REQUEST DATED: 05/7/2012
SDG&E RESPONSE DATED: 05/21/2012

Question 7: Please provide an explanation of why SDG&E has decided to allocate 100% of its distribution demand costs to the non-coincident demand charge of its medium/large C&I rate schedules. See Testimony of Cynthia Fang, at Chapter 2, page CF-17, lines 8-9. Is this proposal consistent with SDG&E's position in past GRC Phase 2 cases?

SDG&E Response 07:

As stated on page CF-16, lines 1-7 of Cynthia Fang's direct testimony (Chapter 2 filed on March 30, 2012), SDG&E is proposing moving from the current recovery of demand-related distribution costs based on approximately 60% non-coincident and 40% peak demand charges to 100% non-coincident demand charges. The reason for this change is described in the following cite from Chris Yunker's direct testimony (Chapter 1 filed in February 2012):

> "C. **Customer-Level Costs Are Created by Customer-Specific Use**
> When looking at customer-specific, demand-related costs, the measure that most accurately reflects the costs incurred to provide distribution services is non-coincident use, as opposed to use coincident with the system peak demand. This is because circuits peak at different times and circuits are built and maintained based on the energy use of the customers on an individual circuit. Non-coincident use, or a customer's use independent of the timing of other customer's use, is an appropriate way to allocate costs when a cost is not tied to the system peak." (p. CY-6, lines 25-31)

SEIA DATA REQUEST NUMBER DRA-01
SDG&E 2012 GRC PHASE 2 A.11-10-002
REQUEST DATED: 05/7/2012
SDG&E RESPONSE DATED: 05/21/2012

Question 9: The Testimony of Cynthia Fang, on page CF-12-I, states that "SDG&E plans to incorporate this [EDF] method of analysis in support of our distribution demand class billing determinants."

a. Does this mean that SDG&E has not used this EDF method in its proposal in this case?
b. If SDG&E has not used this EDF method in this case, why not?

SDG&E Response 09:

a. No. Attachment I of Cynthia Fang's direct testimony (Chapter 2) describes the EDF methodology used to comply with Study Requirement #6, adopted in D.08-02-34. As explained on page WGS-3 of Mr. Saxe's direct testimony (Chapter 3), lines 16-22, this EDF type methodology is used in the development of the distribution demand-related Equal Percent of Marginal Costs (EPMC) allocation factors proposed in this proceeding. The class' contribution to circuit and substation peak loads based on methodology explained in Attachment I, pages 11 and 12, of Chapter 2, is used to allocate marginal feeder & local distribution costs and substation costs, respectively, to customer classes. The file attached in response to Question 8 provides the class circuit and substation peak loads used in this proceeding to allocate marginal feeder & local distribution costs and substation costs, respectively.

b. Please see response to Question 9a.

SEIA DATA REQUEST NUMBER DRA-01
SDG&E 2012 GRC PHASE 2 A.11-10-002
REQUEST DATED: 05/7/2012
SDG&E RESPONSE DATED: 05/21/2012

Question 10: This question concerns the "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 that was employed in the regressions used to determine SDG&E's marginal distribution demand costs for (1) feeders & local distribution and (2) substations, as shown in Tables RME-01 and RME-02 of Mr. Ehlers' testimony (Chapter 6).

a. Please provide the workpapers and the sources for this "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012.
b. At what point on the distribution system is this demand measured?
c. If this demand data is not collected at the substation level, please provide comparable "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 at the substation level.
d. If this demand data is not collected at the feeders & local distribution level, please provide comparable "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 at the feeders & local distribution level.

SDG&E Response 10:

a. The attached file contains the source of the historical distribution peak load data and forecasted peak load data for 1998-2012. The tab labeled "Distribution Load" contains the normalized load figures which were employed in the regression calculations found in the "Distribution MC – Second Revision" work paper.

   The Feeders and Local distribution fifteen year investment stream is regressed against the peak load data using the NERA regression method. The "zero intercept" ordinary least squared regression method is used with the slope of the regression line providing the marginal demand cost in $/kW. A similar calculation is used to calculate the substation marginal demand cost.

   TransmissionCustomersVer2.xls

b. The demand data is measured at the system demand level.

c. For its Marginal Distribution Demand Costs study, SDG&E uses distribution demand data collected at the system demand level. The 1998-2012 system level load data is regressed against cumulative substation capacity investments from 1998-2012 to determine the marginal cost of substation related distribution demand. 1998-2012

d. substation level demand data is not used in the Marginal Distribution Demand Cost study and is not available.

e. For its Marginal Distribution Demand Costs study, SDG&E uses distribution demand data collected at a system demand level. The 1998-2012 system level load data is regressed against cumulative feeders and local distribution capacity investments from 1998-2012 to determine the marginal cost of feeders and local distribution related distribution demand. 1998-2012 feeders and local distribution level demand data is not used in the Marginal Distribution Demand Cost study and is not available.

SEIA DATA REQUEST NUMBER DRA-02
SDG&E 2012 GRC PHASE 2 A.11-10-002
REQUEST DATED: 05/22/2012
SDG&E RESPONSE DATED: 06/07/2012

Question 6: This question follows up SDG&E's response to Q10 of SEIA's first data request in this case. This question concerns the "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 that was employed in the regressions used to determine SDG&E's marginal distribution demand costs for (1) feeders & local distribution and (2) substations, as shown in Tables RME-01 and RME-02 of Mr. Ehlers' testimony (Chapter 6).

e. Please confirm that this "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 is based on <u>coincident</u> system peak loads at the distribution level.

f. If this "historical distribution peak load data and forecasted distribution peak load data" for 1998-2012 is based on <u>coincident</u> system peak data, then please explain SDG&E's assertion in response to SEIA Q12 that "coincident peak demand data was not used to develop SDG&E's proposals in this proceeding."

g. How does SDG&E justify the use of coincident peak demand data to calculate marginal distribution costs, when distribution costs are collected from commercial and industrial customers based on their non-coincident peak demands and when a measure of non-coincident demand (the EDF) is used to allocate these marginal cost among customer classes. Shouldn't non-coincident demand at the distribution level be used in the regressions to determine these marginal distribution costs?

SDG&E Response 06:

a. Yes system peak load is used.

b. SDG&E's response to SEIA DR-01, Question 12 should be clarified to state "coincident peak demand data was not used to develop SDG&E's ***rate design*** proposals in this proceeding."

c. Consistent with SDG&E historic treatment, SDG&E used system peak for the development of cumulative incremental load for the reference in developing the regression slope under the NERA regression for the distribution demand costs of substations and feeders/local distribution, as explained in Chapter 6 testimony, pages RME-2 through RME-6 (Second Revised Prepared Direct Testimony of Robert M. Ehlers).

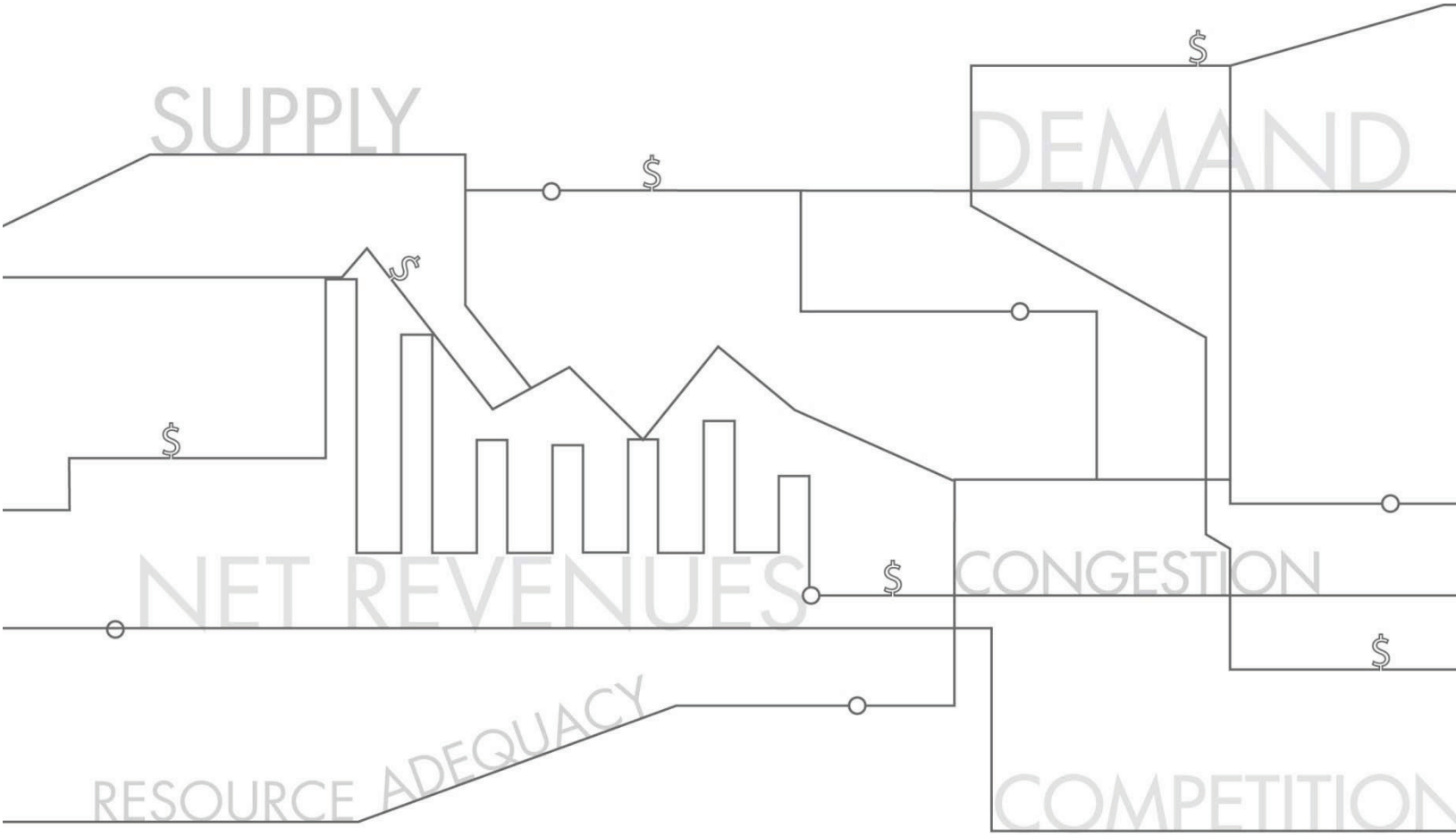
Attachment RTB-4

CAISO 2011 Annual Report

(pages 47-48)

2011 ANNUAL REPORT ON MARKET ISSUES & PERFORMANCE

Department of Market Monitoring



California ISO

Shaping a Renewed Future

Hypothetical combustion turbine unit

Key assumptions used in this analysis for a typical new combustion turbine are shown in Table 1.9. Table 1.10 and Figure 1.16 show estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the real-time energy and non-spinning reserve markets. These results show a decrease in the net revenues in 2011. Estimated net revenues for a hypothetical combustion turbine also fell well short of the $212/kW-year estimate of annualized fixed costs in the CEC report.

These findings continue to underscore the critical importance of long-term contracting as the primary means for facilitating new generation investment. Local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC resource adequacy and long-term procurement framework. Under California's current market design, these programs can provide additional revenue for new generation and cover the gap between annualized capital cost and the simulated net spot market revenues provided in the previous section.

Table 1.9 Assumptions for typical new combustion turbine[31]

Technical Parameters	
Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Startup Gas Consumption	180 MMBtu/start
Heat Rates	
Maximum Capacity	9,300 MBtu/MWh
Minimum Operating Level	9,700 MBtu/MWh
Financial Parameters	
Financing Costs	$146.6 /kW-yr
Insurance	$7.9 kW-yr
Ad Valorem	$10.4 kW-yr
Fixed Annual O&M	$20.3 /kW-yr
Taxes	$26.5 kW-yr
Total Fixed Cost Revenue Requirement	**$211.7/kW-yr**
Variable O&M	$5.1/MWh

[31] The financing costs, insurance, ad valorem, fixed annual O&M and tax costs for a typical unit in this table were derived directly from the data presented in the CEC's *2009 Comparative Costs of California Central Station Electricity Generation Technologies* report which can be found at: http://www.energy.ca.gov/2009publications/CEC-200-2009-017/CEC-200-2009-017-SF.PDF.

Table 1.10 Financial analysis of new combustion turbine (2007-2011)

Components	2007		2008		2009		2010		2011	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	8%	9%	11%	12%	6%	6%	7%	10%	6%	7%
Energy Revenue ($/kW - yr)	$97.54	$104.99	$155.58	$158.98	$70.50	$84.62	$64.97	$95.94	$57.60	$69.57
A/S Revenue ($/kW - yr)	$13.30	$12.83	$5.50	$5.53	$8.64	$8.37	$3.36	$2.97	$6.06	$5.98
Operating Cost ($/kW - yr)	$59.18	$64.63	$100.12	$104.09	$25.85	$27.70	$24.80	$35.60	$23.23	$26.88
Net Revenue ($/kW - yr)	$51.66	$53.19	$60.96	$60.43	$53.29	$65.29	$43.54	$63.32	$40.43	$48.67
5-yr Average ($/kW - yr)	*$49.98*	*$58.18*								

Figure 1.21 Estimated net revenues of new combustion turbine