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Exhibit Number	:	DRA-01
Commissioner	:	Mark J. Ferron
Admin. Law Judge	:	Amy C. Yip-Kikugawa
	:	Stephen C. Roscow
DRA Project Mgr.	:	Lee-Whei Tan
DRA Witnesses		D. Khoury
		R. Levin,
		L. Irwin,
		L.W. Tan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Testimony on San Diego Gas & Electric Company's 2012 General Rate Case, Phase 2 A.11-10-002

San Francisco, California
May 18, 2012

MEMORANDUM

This report was prepared by the Division of Ratepayer Advocates ("DRA") of the California Public Utilities Commission ("Commission") in Application 11-10-002. In this docket, the applicant presents its marginal cost estimates to develop the revenue responsibilities to be assigned to the customer classes. DRA finds that SDG&E overstates the marginal generation and customer costs. DRA also fine-tunes SDG&E's cost allocation and rate design to ensure compliance with legal and regulatory requirements as well as improved economic efficiency. As a result, the residential class would see an average 6.84 percent rate reduction and small commercial customers would see a 3.92 percent rate increase. These compare with SDG&E's proposals to decrease residential rates by 1.36 percent and increase small commercial class rate by 5.79 percent.

Lee-Whei Tan served as DRA's project coordinator in this review, and is responsible for the overall coordination in the preparation of this report. Chris Danforth is the Interim Program Manager who oversaw this project and the review of this report. DRA's witnesses' prepared qualifications and testimony are contained in Appendix A of this report.

List of DRA Witnesses and Respective Chapters

Chapter Number	Description	Witness
-	Executive Summary	
1	Marginal Cost Policy and Methodology	Robert Levin
2	Marginal Cost of Electric Generation	Robert Levin
3	Distribution Demand and Customer Marginal Cost	Louis Irwin
4	Revenue Allocation	Lee-Whei Tan
5	Residential Rate Design	Dexter Khoury
6	Small Commercial Rate Design	Robert Levin
7	Prepay Program	Lee-Whei Tan

EXECUTIVE SUMMARY

In this report, the Division of Ratepayer Advocates ("DRA") presents its testimony for San Diego Gas and Electric Company's ("SDG&E") General Rate Case ("GRC"), Phase II, Application (A.) 11-10-002. This proceeding is intended to establish marginal costs, allocate revenues, and design rates.

DRA has made several recommendations designed to improve the way SDG&E calculates marginal costs. These improvements reduce the revenues allocated to residential and small commercial customers. DRA rejects SDG&E's proposal to introduce a residential basic service fee of $3 per month, and notes that DRA's proposals would help reduce upper tier rates with fewer impacts to other residential customers. DRA recommends a tiered customer charge structure for Small Commercial customers.

Summary of Key DRA Recommendations

I. Marginal Costs

DRA made a number of significant recommendations and modifications to SDG&E's approach on how to calculate marginal costs.

A. Marginal Generation Capacity and Energy Costs

1. DRA recommends an annual capacity value of $100.82 per kW-year, based on a modification to SDG&E's proposed Real Economic Carrying Charge ("RECC") methodology to reflect the lack of need for new generating capacity before 2017.
2. DRA begins with SDG&E's recommended annual average of 4.942 cents per kWh, adds a 1 percent ancillary services adder, and shapes the costs by TOU period using the E3 "Avoided Cost Calculator" hourly factors presented in SDG&E's Chapter 5 Appendix B. Table 1-1 presents DRA's recommended marginal energy costs.

Table 1
DRA's Recommended Marginal Energy Costs

	Summer			Winter		
	On-peak	Semi-peak	Off-peak	On-peak	Semi-peak	Off-peak
MEC (¢/kWh)	6.629	5.391	4.318	6.314	5.291	4.442

B. Marginal Distribution Costs

For delivery marginal costs, DRA accepts SDG&E's recommended distribution demand-related marginal costs of $27.85 per kW-year for substations and $74.06 per kW-year for distribution feeder lines and local distribution.

C. Marginal Customer Access Costs

1. DRA recommends that the Commission adopt marginal customer costs based on the "New Customer Only" ("NCO") methodology, which the Commission has adopted in nearly all litigated marginal cost decisions since 1992. The Commission has repeatedly found that the RECC Method proposed by SDG&E overcharges customers for the cost of their meters, service extensions, and final line transformers.
2. SDG&E's treatment of customer service costs incorrectly assigns identical costs to the smallest and largest customers on the SDG&E system, and greatly departs from the marginal cost showings of SCE and PG&E.

The combined impact of SDG&E's proposed marginal customer costs would greatly disadvantage SDG&E's smaller customers. For these reasons, DRA strongly recommends that the Commission not adopt SDG&E's proposed MCCs. DRA's recommended MCCs are listed below.

Table 2
DRA's Recommended Marginal Customer Costs

	Annual NCO Customer Cost (2012$)
Domestic	$78.22
Small Commercial	$292.99
Medium & Large Commercial & Industrial	$1,286.57
Agricultural	$438.30
Lighting	$13.12

II. Revenue Allocation

DRA recommends the following:

1. DRA's marginal costs to allocate revenue responsibilities;
2. Use of a generation revenue allocator for Energy Efficiency ("EE") and Demand Response ("DR") programs (including dynamic pricing implementation).
3. Allocation of the CARE shortfall by equal cents per kWh.

III. Residential Rate Design

DRA recommends the following:

1. SDG&E's proposal to introduce a residential basic service fee or customer charge of $3 per month should be denied on legal and policy grounds.
2. SDG&E's proposal to consolidate Tier 3 and tier 4 should be denied.
3. A New Cap on CARE tier 3 rates of a maximum of 18 cents per kWh should be adopted until SDG&E's next General Rate Case.
4. SDG&E's proposal to clearly identify total residential rates on its website should be adopted.

IV. Small Commercial Rate Design

DRA recommends the following:

1. Small commercial customers should remain, as a default, under a two-part rate consisting of a fixed monthly customer charge and a volumetric energy rate.
2. SDG&E's proposal to double the current small commercial customer charge to $19.11 per month should be rejected.
3. SDG&E should institute a graduated four-level customer charge as set forth in Table 6-1.
4. SDG&E's Schedule A volumetric rate should be set at $0.18809 per kWh (summer) and $0.14863 per kWh (winter).

V. Prepay Program

DRA recommends that the Commission reject all elements of SDG&E's Prepay Program except for the account management and notification tools that would be made available to participants. The following tools should be offered to all customers who are interested in budgeting and managing their energy expenditures:

1. Customers should be able to set different budget amount thresholds for notification and the frequency of notification.
2. They should be able to customize the channel on which they wish to receive notifications of account balances. The options should include text message, email, and automated phone call.
3. Account balances should be updated daily. Customers should be able to view their daily balance online using "MyAccount" or by telephone accessing an Interactive Voice Response ("IVR") system.

4. Customers should be able to make payments using one of several options:
    a. 24-hour online payment by linking to a bank account and making payments from the bank account using “MyAccount,”
    b. 24-hour online service using a credit or debit card via SDGE’s processing vendor BillMatrix,
    c. By telephone using an automated IVR system, or
    d. By cash or check at one of SDG&E’s branch offices or Authorized Payment Locations.

CHAPTER 1

MARGINAL COST POLICY AND METHODOLOGY

ROBERT LEVIN

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CHAPTER 1

MARGINAL COST POLICY AND METHODOLOGY

ROBERT LEVIN

I. INTRODUCTION

This chapter presents DRA's recommended marginal costs for use in SDG&E's revenue allocation and rate design for 2012 through 2014. It also discusses marginal cost methodology generally and offers a high-level critique of SDG&E's proposed marginal cost methodologies. More detailed analyses of each marginal cost component are offered in the following two chapters.

As in the past, SDG&E presents marginal costs for generation (including separate components for capacity and energy), distribution demand, and customer access. However, SDG&E continues to ignore past Commission marginal cost guidance and sound economic principles. If adopted, SDG&E's proposed marginal costs would be detrimental to economic efficiency and would fail to promote just and reasonable rates.

The Commission has long "...relied on marginal cost principles for assigning revenue requirements to customers (by rate group), and as guidance for setting the level of individual rate components."[1] A major reason for the Commission's reliance on marginal costs is that sound marginal cost-based pricing methodology promotes economic efficiency.[2]

Unfortunately, SDG&E deviates from sound marginal cost methodology in several of its marginal cost components, most notably its marginal generation capacity cost ("MGCC") and its marginal customer cost. With respect to the

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[1] A.11-06-007, Ex. SCE-02, p. 1.

[2] "We have chosen marginal costs as our foundation for allocation and rate design. We have used marginal costs to promote economic efficiency and to provide the greatest good for the greatest number." (Re PG&E (1981) 7 CPUC 2d 349, 1981 Cal. PUC LEXIS 1279 *285, D.93887); "First, economic efficiency dictates that rates be based on marginal cost, not embedded cost." (Re Rate Design for Unbundled Gas Utility Services (1986) 22 CPUC 2d 444, 456, 1986 Cal. PUC LEXIS 753 *17, D. 86-12-009.)

former, SDG&E's marginal cost showing ignores established Commission policy calling for a longer, six-year period for the analysis of the marginal generation capacity cost ("MGCC"), and, under conditions of near-term surplus capacity, a downward adjustment in the MGCC estimate.[3]

SDG&E's proposed MGCC is based on an assumed installation of a new combustion turbine ("CT") in 2012. Yet, as Chapter 2 will show, no new generation capacity is needed for reliability in the 2012–2014 timeframe by any of the major California Investor Owned Utilities ("IOUs"). DRA finds that SDG&E's assumption of a 2012 CT installation is at least five years in advance of actual need, and this causes its proposed MGCC to be overstated by nearly 37%.

Further, both SDG&E's MGCC and its marginal customer costs ("MCC") misapply the "real economic carrying charge" ("RECC") methodology, causing these costs to be overstated. In brief, SDG&E's proposed use of the RECC methodology does not accord with economically correct and Commission adopted marginal cost methodology. Moreover, it results in overestimated marginal costs for generation capacity and customer access, to the detriment of economic efficiency and equitable revenue allocation. This issue is discussed further in this chapter (section C.1) as well as in Chapters 2 and 3.

The remainder of this chapter will summarize DRA's marginal cost recommendations and discuss methodological issues that are common to multiple marginal cost categories.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends the following marginal costs, methodologies, and studies.

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[3] See Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*79, D. 96-04-050. See also Application of PG&E (1997) 71 CPUC 2d 212, 1997 Cal. PUC LEXIS 138*26, D.97-03-017.

A. Marginal Generation Capacity and Energy Costs

DRA recommends an annual value of $100.82 per kW-year,[4] based on a modification of SDG&E's proposed RECC methodology to reflect the lack of need for new generating capacity before 2017.

Table 1-1 presents DRA's recommended marginal energy costs by TOU period. DRA begins with SDG&E's recommended annual average of 4.942 cents per kWh, adds a 1% ancillary services adder, and shapes the costs by TOU period according to the E3 "Avoided Cost Calculator" hourly factors presented in SDG&E's Chapter 5 Appendix B.

Table 1-1
DRA Recommended Marginal Energy Costs

	Summer			Winter		
	On-peak	Semi-peak	Off-peak	On-peak	Semi-peak	Off-peak
MEC (¢/kWh)	6.629	5.391	4.318	6.314	5.291	4.442

B. Marginal Distribution Costs

For delivery marginal costs, DRA accepts SDG&E's recommended distribution demand-related marginal costs of $27.85 per kW-year for substations, and $74.06 per kW-year for distribution feeder lines and local distribution. These recommendations reflect DRA's and SDG&E's proposed retention of the Commission's traditional regression-based approach, with only minor changes due to SDG&E's data constraints as discussed in Chapter 3.

C. Marginal Customer Access Costs

DRA recommends that the Commission adopt marginal customer costs based on the "New Customer Only" ("NCO") methodology, which the Commission has adopted in nearly all litigated marginal cost decisions since 1992.

[4] This value includes a 15% resource adequacy adder.

The Commission has repeatedly found that the "Real Economic Carrying Charge ("RECC") Method"[5] proposed by SDG&E overcharges customers for the cost of their meter, service extension,[6] and final line transformer.

In addition to using a methodology repeatedly rejected by the Commission in multiple decisions, SDG&E's treatment of customer services costs incorrectly assigns identical costs to the smallest and largest customers on the SDG&E system, and greatly departs from the marginal cost showings of SCE and PG&E. The combined impact of SDG&E's proposed marginal customer costs would greatly disadvantage SDG&E's smaller customers.

For these reasons, DRA strongly recommends that the Commission not adopt SDG&E's proposed MCCs.

DRA's recommended MCCs are listed below.

Table 1-2

	DRA Annual NCO Customer Cost (2012$)
Domestic	$78.22
Small Commercial	$292.99
Medium & Large Commercial & Industrial	$1,286.57
Agricultural	$438.30
Lighting	$13.12

D. Other Recommendations

DRA recommends that the Commission direct SDG&E to conduct a comprehensive study of its costs to connect new customers to its distribution grid. In its 2015 GRC Phase 2, MCCs should be based on, at a minimum, a statistically valid sample of actual customer connection project costs for connections

[5] Also commonly called the "rental method".

[6] Also called a "service drop", this is the conductor that carries current from the final line transformer to the customer's meter.

completed between 2012 and 2014.[7] Such costs should exclude developer contributions under Rules 15 and 16. SDG&E's methodology may improperly include costs that are paid by developers or customers.[8]

In addition, SDG&E should update the revenue cycle services ("RCS") studies it performed during the electric industry restructuring, to inform a correct presentment of the customer services component of its marginal customer costs.

Grid connection costs (specifically costs of installing meters, service extensions, and final line transformers), as well as costs of customer services, vary by customer class and are a major component of marginal customer access costs. These, in turn, influence the allocation of SDG&E's distribution revenue requirement among its customer classes. The recommended customer connection costs studies are needed to ensure that those allocations are just and reasonable.

III. DISCUSSION

As described by SDG&E,[9] a "real economic carrying charge" ("RECC") methodology is used in the calculation of both MGCC and MCCs. SCE, which also proposed using RECCs for like purposes, described its RECC methodology thusly:

> When computing marginal costs, SCE converts capital investments into annual costs using a real economic carrying charge (RECC). This approach is sometimes called the economic deferral or rental value method. Under this approach … the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed, and then compared to the present worth of an equivalent asset and its replacements installed one year later. The only difference between these two scenarios is that SCE loses the opportunity to use the asset in the first year of the second scenario. Thus, the difference in present worth between the two scenarios measures the economic (opportunity) cost of using the asset during the first year. The resulting annual charge, when escalated at the rate of inflation over time and then discounted,

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[7] PG&E has based its proposed MCCs on such a study since its 2003 GRC Phase 2.

[8] These assertions are explained in Chapter 3 of DRA's testimony in this proceeding.

[9] A.11-06-007, Ex. SCE-02, p. 12.

> yields the original cost (in terms of revenue requirement) of the investment …. the RECC results in the same real payment over time. This conclusion is important because in real terms the charge for an asset is the same over time and, assuming electricity customers value the service they receive, the charge should be the same regardless of the age of the equipment. Therefore, the proper charge can be calculated for both existing and new customers by applying the RECC to the current cost of the equipment.

DRA understands that the same rationale would apply to SDG&E's use of the RECC in marginal cost estimation. In effect, the RECC results in annual payments that rise with inflation and collect the associated revenue requirement, for an investment made in the first year of SDG&E's planning horizon, over the life of the facility.

DRA finds that RECC is an appropriate starting point for many marginal cost calculations. It is appropriate for annualizing the cost of investments for new equipment when such investments occur in the first year of the planning horizon. Use of an RECC also is appropriate for use in conjunction with the Regression Method used for marginal demand-related distribution costs. However, the RECC methodology overstates the marginal cost of both existing utility plant (e.g., customer hookup facilities) as well as capital investments (e.g., future generation capacity investments) not needed in the immediate future. It does so by (1) overstating the opportunity cost associated with existing hookup equipment, and (2) failing to adjust the cost of capacity investments for the time value of money when there is no immediate capacity need.

A fundamental issue in utility marginal cost ratemaking is whether or not marginal costs should reflect the timing of future demand-related investments.[10] From time to time, some parties, most notably SCE, have proposed to base

[10] This issue arises for marginal capacity costs when capacity investments are "lumpy," that is, they tend to be large and occur infrequently, as may be the case for generation capacity. Lumpiness is less a concern for distribution capacity, at least at the utility system level. In the regression method, historical cost data for many small and medium sized demand-related distribution investments are aggregated. For a large utility, the resulting stream of annual costs is generally "smooth" and timing of individual capital investments is not an issue.

marginal costs on the cost of replacing existing facilities with new facilities, regardless of the need for or timing of such replacements, or the need for new capacity.[11] The Commission most often, and correctly, has rejected such "replacement cost new" ("RCN") methodologies, because RCN does not accurately capture the change in costs caused by a change in demand.

Over the last 30 years, the Commission has generally adhered to the correct incremental definition of marginal cost it adopted in 1981:

> *Marginal costs may be defined as the change in total cost which results from a change in output. The result of using marginal cost in rate setting is that the rate equals the cost of producing one more unit, or the savings from producing one less unit.*[12]

A TURN protest in an earlier SCE rate proceeding stated:

> *The Commission's existing marginal cost methodologies generally set rates based upon the answers it determines to the following questions:*
>
> 1. *What costs change if the utility adds a customer?*
> 2. *What costs change if the utility adds a kilowatt of demand (sometimes defined as a kilowatt of demand at a particular location)?*[13]

The answers to these questions depend upon the amount of surplus capacity relative to customer demand. The principle that **marginal costs should signal the amount of surplus capacity and the timing of new additions** was stated by the Commission in 1990 and again in 1992:

> ***Prices …should recognize that some customers cause demand for system additions more than others, and some cause demand for additions sooner than others. To recognize these differences between customer groups, [marginal cost] studies should incorporate an adjustment***

[11] Cf. A.02-05-004, SCE GRC Phase 2.

[12] OII No. 67 (1981) 5 CPUC 2d 620, Appendix B, 1981 Cal. PUC LEXIS 597*3, D. 92749.

[13] Protest of The Utility Reform Network, February 11, 2000, in A.00-01-009.

which takes into account the proximity or distance of actual planned additions)….[14]

…our goal is to continue to improve our methodology of sending the most accurate marginal cost price signals to PG&E's customers. Because this is our goal, we agree with PG&E's policy principles that marginal cost components should…capture the timing and magnitude of future investments…[15]
The economic intuition behind this principle is that MCs should "be low in times of capacity surplus, rising to full cost when capacity is constrained."[16]

This principle implies that marginal costs should vary over time depending on the amount of existing surplus capacity. Immediately before a major investment, which is intended to resolve an anticipated capacity shortage, marginal capacity costs should be high. After the investment, when excess capacity exists, marginal capacity costs should be reduced to a low level. **Accordingly, the Commission historically has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity.**

This issue has not been addressed in GRC Phase 2 decisions recently since those cases have been settled for over a decade. However, in one of the more recently litigated SCE decisions dealing with generation marginal cost issues (D.96-04-050), the Commission reaffirmed its previous guidance that marginal costs should be reduced at times of near-term capacity surplus. To understand this guidance, one must understand that, during the 1990s, the Commission used an "Energy Reliability Index" ("ERI") to adjust the marginal generation capacity costs to reflect near-term surplus capacity. In its Test Year 1995 GRC, SCE

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[14] OII into Rate Design for Unbundled Gas Utility Services (1990) 37 CPUC 2d 66, 1990 Cal. PUC LEXIS 766*10, D.90-07-055, emphasis added.

[15] Application of PG&E (1992) 47 CPUC 2d 143, 1992 Cal. PUC LEXIS 971*13, D.92-12-057, mimeo, pp. 235-236.

[16] OII Implementing A Rate Design, (1992) 47 CPUC 2d 438, 1992 Cal.PUC LEXIS 970*43, D.92-12-058, mimeo, p. 33, quoted from CACD Workshop Report.

proposed an ERI of 1.0, reflecting **no adjustment** for near-term surplus capacity.[17] In resolving that Application, the Commission stated:

> *The CT cost is … adjusted by an Energy Reliability Index (ERI). The ERI reflects the actual situation faced by Edison in maintaining reliable generation service. When a utility needs capacity to increase reliability of service, its ERI is 1.0 and marginal costs include all the costs of a CT. As capacity is added and reserve margin increases, the value of incremental capacity declines and the ERI drops below 1.0.*[18] *(D.96-04-050, p. 52)*
>
> *…several parties take issue with Edison's use of a 1.0 ERI. Edison argues that an ERI of 1.0 is appropriate because its system is designed to meet customers' needs for reliable firm capacity "for an indefinite period." Accordingly, Edison believes that marginal generation costs should reflect the long-run need for capacity by including the full cost of a CT...*[19]
>
> *DRA, CFBF, and CLECA recommend the use of a six-year average ERI of 0.85. They argue that a six-year average appropriately balances both long-run and short-run considerations, including the near-term market conditions...*[20]
>
> *As discussed above, we believe that marginal costs for use in revenue allocation and rate design should appropriately reflect expected year-to-year price variations during the forecast period. A six-year average ERI is consistent with this approach…*[21]
>
> *…we continue to find its arguments for an ERA of 1.0 to be unpersuasive. Moreover, Edison's preference to ignore short-term capacity conditions in the valuation of marginal generation costs is inconsistent with how we evaluate the capacity value of new resource additions, such as DSM …. We adopt an ERA of 0.85…*[22]

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[17] This proposal, which was rejected in D.96-04-050, is identical to SDG&E's current proposal in A.11-10-002.

[18] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*76, D.96-04-050, mimeo, p. 52.

[19] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*78, D.96-04-050, mimeo, p. 54.

[20] Id.

[21] Id.

[22] In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS

(continued on next page)

Although the ERI methodology of the 1990s may be obsolete, the economic principles embodied in D.96-04-050 remain valid and are equally relevant today. Furthermore, they are consistent with mainstream economic thought. Most economists agree that the marginal cost concept most relevant for ratemaking takes into account the near-term existence or lack of surplus capacity.[23] **In other words, marginal cost should consider not simply the cost of the next unit of supply, but should reflect the cost of serving the next unit of customer demand.**

There is much support in the economics literature for basing marginal cost estimates on demand, considered in conjunction with supply, rather than on supply costs alone. SDG&E's RECC methodology is based solely on supply (i.e., capacity) costs without regard for demand. This cannot be correct in a period with excess capacity: As stated by Alfred Kahn **"…the intensity and elasticity of demand help determine the level of marginal costs.**"[24]

In a similar vein, Nobel Laureate (in economics) Sir Ronald Coase stated:[25]

> *In calculating the costs of an additional supply of a public utility service, it is of course necessary to start with the industry as it is, with whatever assets it possesses and the circumstances in which it finds itself.* ***Costs are rooted in the actual situation.***[26]

This is a clear statement that marginal cost methodology should be based on real utility investment plans (which consider the timing of need), rather than on the undiscounted cost of capacity when such capacity may not be required for

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(continued from previous page)
270*79, D.96-04-050, mimeo, p. 55, emphasis added. See also Finding of Fact 25 in this Decision.

[23] See, for example, Kahn, Alfred (1970). "The Economics of Regulation," The MIT Press. http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948. Retrieved 2010-11-30, pp. 70-71.

[24] Kahn, p. 89.

[25] R. H. Coase, "The Theory of Public Utility Pricing and Its Application," Bell Journal of Economics and Management Science, Volume 1, No. 1 (Spring 1970), p. 123.

[26] R. H. Coase, "The Theory of Public Utility Pricing and Its Application," Bell Journal of Economics and Management Science, Volume 1, No. 1 (Spring 1970), p. 123, emphasis added.

several years into the future. Chapter 2 of DRA's testimony discusses how this principle applies in the context of marginal generation capacity cost. As discussed, generation reserve margins are now well above target levels and are forecast to remain so throughout 2012 to 2014. This implies that SDG&E is now at a time of near-term excess generating capacity.

An unadjusted RECC Methodology Overstates Marginal Costs At Times of Excess Capacity. As noted above, SDG&E's RECC approach does not adjust for the timing of future capacity investments. If capacity is not needed until say, five years into the future, it does not discount such costs back to the present, as suggested by Kahn.[27] SDG&E's RECC approach fails to account correctly for the time value of money when no current capacity investments are needed. Estimating marginal costs based on discounting future investment costs leads to the following comparisons shown in Table 1-3:

Table 1-3
Adjustment of Future Costs for the Time Value of Money[28]

Year of Investment	Year	Adjustment Factor for Time Value of Money		Percent Overstatement of Costs By Unadjusted RECC Method
		RECC Method	Correct Adjustment	
1	2012	1.0	1	0%
2	2013	1.0	0.939	6.5%
3	2014	1.0	0.882	13.4%
4	2015	1.0	0.828	20.8%
5	2016	1.0	0.778	28.6%
6	2017	1.0	0.730	37.0%
7	2018	1.0	0.686	45.9%
8	2019	1.0	0.644	55.3%
9	2020	1.0	0.605	65.4%
10	2021	1.0	0.568	76.2%

[27] Kahn, p. 104, footnote 47. Kahn's suggestion is discussed extensively in Chapter 2.

[28] Data in this table are based on SDG&E's assumptions of a 8.4% discount rate and an inflation rate of 1.79% which it uses to estimate its generation RECC.

The overstatement of costs, shown in Table 1-3, potentially applies to SDG&E's use of the RECC methodology in both marginal generation capacity costs ("MGCCs") and marginal customer costs ("MCCs").

For MGCCs, SDG&E's RECC methodology would be correct in concept if SDG&E were required to invest in new generation capacity in 2012 to maintain accepted service reliability standards. However, as indicated in Chapter 2, SDG&E will not require additional generation capacity until at least 2017, the sixth year of the six-year planning horizon that the Commission has established for purposes of estimating MGCC. According to Table 1-3, SDG&E's RECC methodology would overstate the correct 2012 marginal cost by 37%. Therefore, the Commission should not adopt SDG&E's RECC-based MGCC; it is too high because it does not properly reflect the time value of money. Chapter 2 presents DRA's detailed justification for its recommendations concerning SDG&E's MGCC.

In a similar vein, Chapter 3 discusses how the Commission has consistently found that applying the RECC methodology applied to customer hookup equipment overstates SDG&E's marginal customer access costs. This application of the RECC is often called the "rental method." These access costs include the capital costs of customer access equipment such as final line transformers ("FLTs").[29] SDG&E's FLTs are assigned a 30-year service life, and SDG&E's field-installed FLTs have vintages ranging from new to 30 years old, or older. For FLTs newly installed in 2012, the RECC methodology would yield the correct marginal cost. It would exactly recover the capital-related costs of the newly installed FLT over its service life spanning 2012 through 2041.

However, this approach would overstate the cost of an existing FLT which could be due, for example, for replacement in year 6 (2017 in this case). A correct 2012 marginal cost analysis would adjust the 2012 cost by a factor of 0.73

[29] Customer access (or hookup) equipment consists of meters, service extensions, and FLTs. The latter comprise about 60% of SDG&E's hookup equipment by dollar weight. DRA discusses customer access marginal costs in Chapter 3.

to account for the time value of money and inflation over the period 2012 to 2017.[30] Likewise, a FLT that does not need to be replaced until 2021 would be adjusted using a cost factor of 0.57. SDG&E's RECC methodology fails to make these adjustments. Instead, SDG&E's RECC methodology treats all FLTs (and other customer hookup equipment) as if it were being replaced in 2012. For an item not due for replacement until 2017 or 2021, SDG&E's methodology overstates costs by 37% or 76% respectively (per Table 1-3). The magnitude of the overstatement for the entire stock of FLTs could be significant given that this equipment probably has a service life exceeding 30 years and the distribution of vintages can be assumed to be fairly uniform.

As explained in Chapter 3, the economic value (or opportunity cost) of an existing utility distribution system (including customer hookup facilities) is considerably less than the "replacement cost new" ("RCN") value embodied in SDG&E's use of RECC methodology in marginal customer costs. RECC methodology ignores both sunk costs and economic depreciation associated with existing facilities. Use of the RECC methodology, as proposed by SDG&E, would greatly overcharge customers for their hookup facilities. This assertion is consistent with numerous previous Commission findings in a series of decisions rejecting the rental methodology.[31]

IV. CONCLUSION

The Commission has a long history of either rejecting the RECC methodology outright (in the case of marginal customer hookup costs) or adjusting it downward to reflect near-term capacity surplus (in the case of marginal generation capacity costs). SDG&E, in offering the identical RECC methodology

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[30] Per Table 1-3, which is based on SDG&E's assumed 8.4% discount rate and 1.79% inflation rate.

[31] See, for example, <u>In the Matter of the Application of SCE</u> (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*79, D.96-04-050, Findings of Fact 37 and 38. Other decisions are cited in Chapter 3.

that the Commission has repeatedly rejected, is swimming against the mainstream of economic thought as well as Commission precedent.

By failing to reflect near-term lack of need for new investments, SDG&E’s proposals overstate both types of marginal costs, to the detriment of economic efficiency. The Commission should reject SDG&E’s unadjusted RECC proposals for both marginal generation capacity and customer hookup costs.

CHAPTER 2

MARGINAL COST OF ELECTRIC GENERATION

ROBERT LEVIN

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CHAPTER 2

MARGINAL COST POLICY AND METHODOLOGY

ROBERT LEVIN

I. INTRODUCTION

SDG&E presents separate marginal cost components for generation capacity and energy, as has been the practice during most of the Commission's thirty-year history of basing electric rates on marginal costs. For the marginal generation capacity cost, DRA recommends an annual value of $100.82 per kW-year,[1] including a 15% resource adequacy adder, based on a modification of SDG&E's proposed RECC methodology to reflect the lack of need for new generating capacity before 2017. For marginal energy costs, DRA accepts SDG&E's proposed annual average value of 4.942 cents per kWh, but adds 1% to include marginal ancillary services costs.[2] DRA also recommends that the resulting annual average value of 4.991[3] cents per kWh be shaped by time-of-use ("TOU") period according to the factors derived by Energy and Environmental Economics ("E3"), as presented in Appendix B of SDG&E's Chapter 5.

As described by SDG&E:

> *The purpose of marginal cost based ratemaking is to send customers a price signal that will encourage them to consume electricity efficiently. Marginal commodity costs are the incremental electric commodity costs incurred on behalf of utility customers, and are composed of marginal energy costs and marginal generation capacity costs. Marginal energy costs (MEC) are the added energy costs incurred to meet the projected growth in electricity consumption. Marginal generation capacity costs (MGCC) relate to the added costs*

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[1] SDG&E's proposed MGCC ($120.06 per kW-year) excludes the 15% resource adequacy adder. On a comparable basis (excluding the adder), DRA proposes $87.67 per kW-year.

[2] DRA is following TURN's recommendation in SCE GRC Phase 2 (A.11-06-007) for a 1% ancillary services adder in SCE's marginal energy costs. E3 has a similar component in its avoided cost calculators.

[3] 4.942 cents per kWh increased by 1%.

incurred to meet the projected growth in peak electric demand.[4]

DRA agrees, in general, with this SDG&E testimony and, in particular, with SDG&E's proposal to separate the energy and capacity marginal cost components. However, DRA disagrees with SDG&E's strictly long-run approach to estimating the MGCC. SDG&E bases its MGCC proposal on "the cost of building a new combustion turbine in the San Diego area [in 2012] …",[5] regardless of the near-term need for such a facility.

A. Marginal Generation Capacity Costs

While SDG&E would be correct to state that the Commission has used the deferral value of a combustion turbine ("CT") proxy for estimating the avoided cost of capacity,[6] SDG&E neglects to consider the key fact that the Commission has a long history of adjusting the CT deferral value downward, reflecting a reduced marginal generation capacity cost ("MGCC") when surplus capacity exists.

As discussed in Chapter 1, for nearly a decade the Commission used an "Energy Reliability Index" ("ERI") to adjust the annualized CT cost downward when it found the existence of near-term surplus capacity. The ERI methodology fell out of use with electric industry restructuring of the late 1990s and the implementation of new markets where capacity costs were at least partly recovered in energy prices. The ERI methodology is now considered obsolete. After a hiatus during the electric industry restructuring[7], the Commission reinstated separate marginal cost components for capacity and energy. Since 2001, the capacity costs always have resulted from various settlements in Phase 2

4 Ex. SDG&E-105, p. DTB-1.

5 Ex. SDG&E-105, p. DTB-6.

6 Equivalently, the CT cost, annualized in real dollars using an RECC factor.

7 For a time, some utilities used Power Exchange prices in lieu of presenting MEC and MGCC. PG&E's 1999 GRC Phase 2 filing was an example. That proceeding was permanently suspended due to the energy crisis.

of the General Rate Cases. While some parties proposed to use the full annualized cost of capacity, other parties proposed lower values, and the settled values have generally been somewhat below the full annualized capacity cost.

There are at least two factors that could, and should, reduce that MGCC below the real economic carrying cost of a CT. First, one could deduct the "market earnings" of a new CT, defined by SDG&E as including both "energy market earnings" and "ancillary service market earnings."[8] SDG&E proposes to deduct its estimate of CT market earnings, resulting in about a 21% reduction to its full CT proxy cost.[9]

The second factor that could, and should, further reduce the MGCC is the existence of a near-term surplus capacity. As discussed below, according to the Commission's Long-Term Planning Proceeding ("LTPP"), no new generation capacity is needed in California through at least 2017. As discussed in Chapter 1, both Commission precedent and mainstream economic theory dictate that the marginal capacity cost used to set retail prices should be reduced, relative to its long-run value, when near-term surplus capacity exists.

DRA finds that SDG&E's proposed MGCC values are overestimated because SDG&E does not adjust MGCC downward to reflect near-term surplus capacity. To correct this defect, DRA proposes an adjustment to SDG&E's MGCC value, which is based on an annualized CT cost, reduced by CT market earnings. As described elsewhere by Southern California Edison ("SCE"), SDG&E's RECC methodology is equivalent to a deferral approach in which "the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed [based on 2012 installation], and then compared to the present worth of an equivalent asset and its replacements installed one year later [in 2013].[10] DRA proposes to modify SDG&E's RECC approach by computing

[8] Ex. SDG&E-105, p.DTB-7.

[9] Ex. SDG&E-105, p.DTB-7.

[10] A.11-06-007, Ex. SCE-02, p. 12.

the deferral value of a 2017 CT installation deferred to 2018. This adjustment, reflecting the time value of money, reduces the MGCC by about 27%. The detailed justification for DRA's approach is presented below.

B. Marginal Energy Costs

With respect to marginal energy costs ("MEC"), SDG&E presents averaged MEC for the 2012-2014 period by its six time-of-use periods. MECs generally have two independent attributes, their average level and their "shape:" the latter accounts for the relationship (ratio) between MECs in the various TOU periods to their annual average value. SDG&E estimated the annual average level of the MEC at 4.942 Cents per kWh, based on an average of forward prices for CAISO zone SP-15 for calendar years 2013-2014. DRA accepts this estimate as a starting value, and notes that it is nearly identical to SCE's annual average MEC for the same period, filed in its GRC Phase 2 (A.11-06-007) just four months before SDG&E's filing. However, DRA proposes a 1% marginal energy cost adder to reflect the cost of additional ancillary services.

In respect to "shape," SDG&E's proposed MECs are based on an apparently non-statistical and non model-based methodology utilizing "pricing factors" developed in-house.[11] The hourly MEC estimates developed by this approach are averaged over the various TOU periods associated with SDG&E's rate schedules. DRA has serious reservations, discussed below, about SDG&E's approach to the development of hourly MEC price profiles or "shape." DRA agrees with the comments of SDG&E's own witness, that this approach is "somewhat simplistic."[12]

DRA does not accept SDG&E's proposed shaping of the MECs. DRA compared SDG&E's proposed MECs with other recent and relevant MEC forecasts for SCE,[13] primarily for shape, and also noted also the comparisons

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[11] Ex. SDG&E-105, Appendix B, pp.DTB-1-B & DTB-2-B.

[12] Ex. SDG&E-105, Appendix B, p. DTB-2-B.

[13] Several parties provided MEC analyses for 2012-2014 in SCE's GRC Phase 2 (A.11-06-007).

(continued on next page)

presented by SDG&E.[14] In general, SDG&E's proposed MECs are "peakier" than most of TOU profiles that DRA examined, as well as the comparison cases that SDG&E presented in Appendix B. That is, SDG&E's MEC results show more variation between the on-peak and off-peak periods, as compared to recent public data and other parties' MEC forecasts.

Finally, DRA considered including an RPS adder[15] in its MECs, but is not proposing one at this time. While DRA believes that the concept of an RPS adder has merit, it is unclear how to quantify it. Issues raised by the possible inclusion of an RPS adder in the MEC are discussed below.

II. SUMMARY OF RECOMMENDATIONS

For the marginal generation capacity cost, DRA recommends an annual value of $100.82 per kW-year,[16] including a 15% resource adequacy adder, based on a modification of SDG&E's proposed RECC methodology to reflect lack of need for new generating capacity before 2017.

For the marginal energy cost, DRA recommends an annual average value 4.991 cents per kWh. This is identical to SDG&E's recommendation plus a 1% ancillary services adder; however, DRA's TOU period MECs differ from those of SDG&E. The following are DRA's recommended marginal energy costs by TOU period.

(continued from previous page)
These analyses were developed in about the same timeframe as SDG&E's analysis, and based on similar (SP-15) data. See below for DRA's discussion of the implications of these MEC projections for this SDG&E proceeding.

[14] Ex. SDG&E-105, Appendix B.

[15] That is, a change in energy consumption can affect the costs of compliance with California's Renewable Portfolio Standard ("RPS"). Conceptually, this should affect the MECs.

[16] SDG&E's proposed MGCC ($120.06 per kW-year) excludes the 15% resource adequacy adder. On a comparable basis (excluding the adder), DRA proposes $87.67 per kWh.

Table 2-1

	Summer			Winter		
	On-peak	Semi-peak	Off-peak	On-peak	Semi-peak	Off-peak
MEC (¢/kWh)	6.629	5.391	4.318	6.314	5.291	4.442

While its proposed MECs do not include an RPS adder, DRA may consider such an adder if proposed by other parties.

III. DISCUSSION

A. Marginal Generation Capacity Costs

DRA accepts SDG&E's proposed conceptual framework for calculating MGCC, starting with the real annualized cost of a CT and deducting market earnings, with two exceptions. First, **the Commission historically has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity.** Yet SDG&E proposes no such adjustment. Second, the MGCC should be adjusted upward by 15% to reflect resource adequacy requirements.

1. Marginal Generation Capacity Costs Should Signal the Amount of Surplus Capacity and Timing of New Additions

As discussed in Chapter 1, the principle that **marginal costs should signal the amount of surplus capacity and the timing of new additions** was stated repeatedly by the Commission during the 1990s in the era when marginal costs were litigated rather than adopted through settlements. The Commission has applied this principle in both electric and natural gas contexts.[17] DRA is unaware of any litigated Commission decision that adopted a marginal cost based on the

[17] In D.92-12-058, the Commission rejected a proposal to base the marginal cost of gas transmission on the annualized cost of a new pipeline. The rejected proposal was equivalent to the unadjusted RECC methodology SDG&E proposes here.

full annualized cost of new capacity when near-term surplus capacity was shown to be present.

The capacity costs reflected in the MGCC accordingly must be reduced when there is near-term surplus capacity. SDG&E's failure to adjust its MGCC accordingly runs counter to a long series of Commission decisions epitomized by D.96-04-050, one of the more recently litigated Commission decisions dealing with generation marginal cost issues, which is quoted extensively in Chapter 1.

In D.96-04-050, the Commission reaffirmed its previous guidance that marginal costs should be reduced at times of near-term capacity surplus. SDG&E's failure to reduce its MGCC to reflect near-term surplus capacity also is at variance with mainstream economic thought that marginal costs must take into account demand conditions and should not be based solely on the cost of the next unit of supply (or capacity).[18]

In the next section, DRA will establish the existence of near-term surplus generation capacity and explain in detail how it proposes to adjust SDG&E's MGCC proposal to reflect that surplus capacity.

2. California Will Have Surplus Generation Capacity At Least Through 2016

The Commission utilizes a Long-Term Procurement Planning ("LTPP") process to assess generation capacity needs, typically over a ten-year horizon. The most recent LTPP proceeding (R.10-05-006) was initiated in May, 2010. This LTPP was organized in 3 "tracks," of which Track 1 is relevant here:

(1) **Track I** will identify California Public Utilities Commission (CPUC)-jurisdictional needs for new resources to meet system or local resource adequacy and to consider authorization of IOU procurement to meet that need, including issues related to long-term renewables planning and need for replacement generation infrastructure to eliminate reliance on power plants using once-through-cooling ("OTC").

[18] See, Chapter 1, p. 10.

SDG&E's testimony in A.11-10-002 provides no information about whether SDG&E needs new generation capacity for reliability purposes in 2012, or indeed in any year of the Commission's traditional six-year time horizon for marginal capacity cost analysis (2012 through 2017, in this case). No determination of need for additional generation capacity for SDG&E was made in the 2010 LTPP proceeding.[19,20]

Further indication of near-term surplus capacity can be found in a recent independent (non-Commission sponsored) report by the North American Electric Reliability Corporation ("NERC").[21] NERC examined the resource balance for each of the major sub-regions within the Western Electricity Coordinating Council ("WECC") region. NERC's analysis shows that generation reserve margins will be well above the Commission's 15% to 17% targets through 2021. Figure 2-1 summarizes NERC's findings for Southern California.

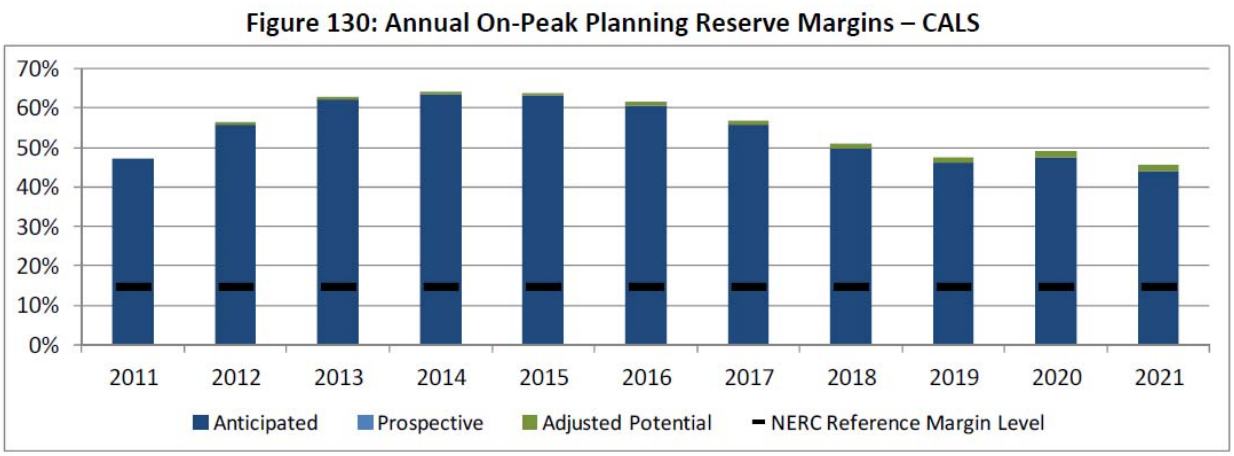
[19] Nor was any need established for PG&E or SCE. In a motion to approve a settlement agreement signed by 23 parties, including SDG&E, the parties stated: "*[t]he Commission does not need to authorize procurement authority relating to LCR [Local Capacity Requirements] for SCE's and PG&E's service areas at this time*" (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 in R.10-05-006.

[20] In approving a proposed settlement of Track 1 issues in the 2010 LTPP proceeding, D.12-04-046 states (p.6) "The settling parties have agreed to defer determination of the core issue in this proceeding: the utilities' future need for additional generation. To the extent there may be any such need, it appears to be primarily driven by the necessity to integrate higher levels of renewable generation onto the system, in anticipation of a 33% renewable portfolio standard (RPS) target. The settling parties state that: "There is general agreement that further analysis is needed before any renewable integration resource need determination is made." (Settlement Agreement at 5.)"

[21] North American Electric Reliability Corporation (NERC) 2011 Long-Term Reliability Assessment, November 2011, p. 463, Fig. 130.

Figure 2-1

NERC Southern California Planning Reserve Projections



3. SDG&E's MGCC Should Be Estimated Based on The Value of Deferral of Capacity from 2017 to 2018

As discussed above, it is likely that 2017 is the soonest that new generation capacity could be needed for reliability purposes in California. Further, 2017 is the last year of the six-year period which begins 2012. The Commission has traditionally adopted a six-year period for estimating MGCC because it balances short-run and long-run capacity needs. For these reasons, DRA bases its MGCC estimate on a scenario that capacity will not be needed during the years 2012 through 2016, but **could** be needed in 2017.[22]

Accordingly, DRA proposes to modify SDG&E's proposed RECC methodology by escalating the CT cost to 2017 and then computing the present value in 2012 of the one-year deferral value of a CT installed in 2017. Incorporating the market earnings adjustment proposed by SDG&E, the effect of the assumed five-year delayed CT installation from 2012 to 2017 reduces the 2012 MGCC from $120.06 per kW-yr to $87.67 per kW-yr.[23]

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[22] DRA emphasizes that it is <u>not</u> forecasting the need for new generating capacity in 2017. It simply accepts that there *could* be a need in 2017, and proposes therefore to base SDG&E's MGCC on the value of deferring CT capacity from 2017 to 2018.

[23] These values exclude the 15% resource adequacy adder discussed below.

DRA's proposed methodology is consistent with marginal cost theory, as articulated by Alfred Kahn. Kahn, in describing a situation in which lumpy investments in capacity occur in anticipation that they will be needed to satisfy future peak demands, states the following:

> *Typically, public utility companies must build in advance of demand in order to be in a position to meet unexpected peak requirements and simply because the investment process is a lumpy one: additions to capacity are most economically made in large units. Therefore at any given time, there is almost certain to be excess capacity, which will remain idle if customers are charged long-run marginal costs.*[24]

Kahn then asks, rhetorically: "What, in these circumstances, is the proper measure of marginal costs?" He answers his own question thusly:

> *…there is a strong economic case for letting price rise and fall as demand shifts…in the presence of excess capacity, no matter how temporary, no business should be turned away that covers the SRMC [short run marginal cost] of supplying it.*[25]

Kahn describes in a footnote how capacity costs could be assigned to current peak period usage even though such usage is not causing an immediate need for new capacity:

> *It might appear that no customer whose continued patronage would eventually require additions to capacity should ever be charged a price that completely excludes those capital costs; the economic ideal, it might appear, would be to include them, but* ***discounted back to the present value****, to reflect the fact that continued service of the customer in question would require their incurrence only sometime in the future.*[26]

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[24] Kahn, Alfred, The Economics of Regulation (1970), p. 104. (see http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948.)

[25] Id at p. 104.

[26] Kahn, Alfred, The Economics of Regulation (1970), p. 104, footnote 47, emphasis added. (see http://mitpress.mit.edu/catalog/item/default.asp?ttype=2&tid=5948.) The reader may note the phrase "it might appear." This caveat refers to the subsequent statement (in the same footnote): "*Such a prescription ignores the fact that buyers whose continued patronage could require the incurrence of additional capacity costs are not in fact responsible for them if they*

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In the current context, therefore, DRA believes that it is entirely consistent with economic theory, when near-term surplus capacity exists, to charge current on-peak electricity users a substantial fraction, but not 100%, of the full long-run cost of capacity. DRA proposes to use the traditional RECC approach applied to a CT proxy installed in 2017, but **discounted back to the present value** as described by Kahn.[27] For the 8.4% discount rate and 1.79% inflation rate[28] proposed by SDG&E, discounting back to the present value results in about a 32% reduction, from $120.06 per kW-yr to $87.67 per kW-yr.

4. SDG&E's MGCC Should Be Adjusted Upward by 15% to Reflect Resource Adequacy Constraints

DRA notes that the MGCC value proposed by SDG&E excludes a resource adequacy adder.[29] Such an adder should be included to reflect the fact that each additional kW of customer demand causes the need for 1.15 kW of additional generation capacity. This is a result of a requirement, instituted in the Commission's Resource Adequacy proceeding, that utilities maintain a planning reserve margin of at least 15%.[30]

(continued from previous page)
drop out of the market when the time comes for the supplying company to make the decision whether to make the additional investment."
DRA believes that Kahn's caveat does not apply, in the main, to electricity, because most electrical equipment has an expected lifetime of five years or more, and so, any change in current electricity consumption due to acquisition of new or replacement electrical equipment or appliances is likely to be of long duration and is likely, therefore, to affect future capacity needs.

[27] Id. The necessary adjustment is given by the formula: Y = X (1+i)^n/(1+r)^n where Y is the adjusted capacity value, X is the unadjusted capacity value proposed by SDG&E, i is the inflation rate, r is the discount rate, n is the number of years elapsed (5, in this case) between the test year and the year of capacity need), and "^" denotes exponentiation.

[28] This value does not appear to be in SDG&E's testimony or workpapers, but was contained in an Excel spreadsheet "RECC Factors" attached to an e-mail sent to DRA by SDG&E witness Mr. Matt Ehlers on May 3, 2012.

[29] SDG&E's MGCC calculation is shown in Ex. SDG&E-105, Table DTB-2, p. DTB-8. SDG&E acknowledged its omission of the 1.15 factor in a response to DRA data request DRA-07, dated February 22, 2012.

[30] As described on the Commission's website: "The CPUC adopted a Resource Adequacy (RA) policy framework (PU Code section 380) in 2004 to in order to ensure the reliability of electric service in California. The CPUC established RA obligations applicable to all Load Serving

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SDG&E characterizes marginal commodity costs as "the incremental electric commodity costs incurred on behalf of utility customers." DRA concurs, but would further characterize marginal capacity costs as "incremental capacity costs incurred to meet an additional kW of customer demand." The correctness of adding 15% to account for the RA requirement stems from this economic definition of marginal cost.

This proposed 15% adjustment is not new: a 1.15 "Capacity Response Ratio" ("CRR") factor was also adopted in D.96-04-050 and used to adjust the MGCC upward.[31] The need for such an adjustment has been recognized by both PG&E and SCE.[32]

5. Summary and Comparison of SDG&E's and DRA's Proposed MGCC Values

In summary, DRA's proposed MGCC differs from SDG&E's in two respects:

1. DRA reduces the MGCC value proposed by SDG&E by about 27% to adjust for the time value of money, reflecting a 2017 to 2018 deferral rather than a 2012 to 2013 deferral; and

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(continued from previous page)
Entities (LSEs) within the CPUC's jurisdiction, including investor owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs)."

"Each LSE is required to file with the Commission demonstrating that they have procured sufficient capacity resources including reserves needed to serve its aggregate system load on a monthly basis. Each LSE's system requirement is 100 percent of its total forecast load plus a 15 percent reserve, for a total of 115 percent."

[31] See In the Matter of the Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270*76 and *78, D.96-04-050, p. 52 and p. 54. While the 15% adjustment could be made in the revenue allocation stage instead of including the 15% factor explicitly in the marginal cost, DRA believes its inclusion in the marginal costs is needed to ensure the correct evaluation of the cost impact of a 1 kW change in customer demand.

[32] In an e-mail sent on December 1, 2011 from Mr. Russell Garwacki, SCE stated: "In determining Marginal Cost Revenue Responsibility for generation, SCE omitted making an adjustment to the generation capacity marginal cost revenue requirement to reflect a 15% planning reserve margin (PRM) under resource adequacy (RA). The (PRM) should be included as SCE will need to procure PRM capacity for each additional MW of load growth. This results in a 15% increase in the cost for capacity. The PRM is already included in the determination of the cost for capacity for dynamic pricing and demand response programs."

2. DRA increases the MGCC by 15% to account for resource adequacy constraints.

The following table compares SDG&E's and DRA's MGCC values, with, and without the 15% resource adequacy adder.

Table 2-2
Comparison of SDG&E and DRA Proposed MGCC Values

	Without 15% adder	With 15% Adder
SDG&E Proposed MGCC	$120.06	$138.07[33]
DRA Proposed MGCC	$87.67	$100.82

B. Marginal Energy Costs

As discussed above, MECs generally have two independent attributes, their average level and their "shape." The former is determined predominantly by fuel costs. The latter captures the variation in costs caused by changes in demand by time-of-use period. Typically MEC is lowest in off-peak periods and highest at times of peak demand, as less efficient generating units must be placed into operation in periods of higher demand.

As stated in the introduction to this chapter, DRA accepts SDG&E's proposed annual average MEC with a 1% adjustment for ancillary services costs, but rejects SDG&E's proposed hourly and TOU period MEC price profiles. DRA's analysis and recommendations are described below.

1. The "Level" of SDG&E's Marginal Energy Costs

SDG&E states that its MEC level is based on an average of electricity forward prices for SP-15 for calendar years 2013–2014.[34] While the methodology that SCE used to estimate MEC in its nearly contemporaneous GRC Phase 2[35] was different from that proposed by SDG&E, a comparison would be

[33] SDG&E's proposed value of $120.06 per kWh x 1.15.

[34] Ex. SDG&E-105, p.DTB-3.

[35] A.11-06-007.

useful. SDG&E's MEC recommendation, 4.942 cents per kWh, is almost identical to the MEC value SCE recommended in A.11-06-007. SCE's MEC proposal was based on a three-year average gas price of $5.36 per million British thermal unit ("MMBtu").[36] This price is well below historical levels and also is below the levels in a recent report of the California Energy Commission ("CEC"), which states:

> Natural gas is a heavily traded commodities market characterized by inherent volatility. Over just the last decade, natural gas prices spiked several times.[37]

Figure ES-3 of the 2011 CEC Natural Gas Market Assessment report shows both historical gas prices from 2005 through 2011 and CEC's reference case price forecast, as well as three additional "change case" forecasts.[38] According to this Figure, Henry Hub daily spot market natural gas prices were above $6 per MMBtu prior to 2009, and then collapsed to below $4 in 2009 through 2011. However, in all four CEC forecasts, prices are expected to return to the $6 level or above, by 2013. According to the CEC:

> The Reference Case results suggest that the combination of recession-driven weak demand and abundant domestic supply has driven current wholesale market prices significantly below the … highs of a few years ago. These conditions are projected to be temporary as:
>
> 1. Future demand increases with economic recovery and diminishing opportunities on the production side
> 2. Prices rise as production marches up the marginal cost supply curve….
> 3. Even with returning demand, prices could plateau at about $6.00/MMbtu (2010$).[39]

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[36] Id, p. 21.

[37] CEC Draft Staff Report: 2011 Natural Gas Market Assessment: Outlook, September, 2011, CEC-200-2011-012-SD, p. 4.

[38] Id, p. 8.

[39] Id, p. 6.

The CEC further states:

> *The spot purchase price of natural gas at the Louisiana trading hub called Henry Hub is a nationally important market price benchmark. Currently, natural gas prices at Henry Hub are in the low $4/MMBtu range (in 2010$). Current spot prices of natural gas reflect a large supply from shale natural gas and a slow economy. Much of the natural gas production is occurring on leased land where many gas developers must drill for gas soon or lose their lease. Since demand is low due to the recession, the resulting temporary oversupply situation pushes current market prices down.*[40]

While natural gas prices have indeed dropped since both the October 2011 SDG&E forecasts and July 2011 SCE MEC forecasts were developed, DRA finds that the CEC natural gas price analysis qualitatively credible.[41] In light of the great uncertainty in natural gas prices in 2012-2014, DRA now believes that SDG&E's MEC level of 4.942 cents per kWh, which assume a gas price similar to SCE's of $5.36 per MMBtu, represents a reasonable middle ground between today's historically low gas prices near or below $4 per MMBtu and the CEC's forecast of the return of higher prices of around $6 per MMBtu. For these reasons, DRA accepts the proposed annual average level of SDG&E's proposed MECs, subject to a 1% increase to include marginal ancillary services costs.

2. The "Shape" of SDG&E's Marginal Energy Costs

SDG&E's proposed summer season on-peak MEC is 41.9% above its annual average. SDG&E's proposed MECs are significantly "peakier" than those seen in recent California Independent System Operator ("CAISO") data. SDG&E describes its methodology for estimating its hourly price profiles in some detail in Attachment B of its testimony.[42]

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[40] Id, p. 42.

[41] That is, DRA finds the CEC forecasts credible with respect to direction but not necessarily to specific numerical values.

[42] Ex. SDG&E-105, Attachment B, p.DTB-1-B.

Briefly the steps are:

1. Develop an hourly load shape for each month, based on SDG&E loads for the period July 2009 through June 2010, as a ratio of the hourly load to the average hourly load for the applicable peak or off-peak market period.
2. Determine the range of load in each month (difference between maximum and minimum values) for both on and off peak periods.
3. These steps were repeated for 2009-2010 CAISO day-ahead locational marginal prices ("LMPs").
4. "The LMP price ranges were divided by the load ranges for both on-peak and off-peak periods for each month to create pricing factors."[43]
5. "These pricing factors were then applied to the original load shape to produce the market price shape."[44]
6. "Next, the hourly price profile is multiplied by the ratio of forecasted monthly natural gas prices to annual average gas price to account for seasonal variations in gas prices which impact electricity prices."[45]
7. Finally, …, "the average annual 2013-2014 electric market forward market prices are used to establish the average price over the period"…. The 8760 prices resulting from applying the adjusted price profile created in Step 6 to the average annual 2013-2014 electric market forward market price "are then aggregated into weekdays and weekends for each month for use in cost allocation and for use in calculating time-of-use factors that are part of rate design."[46]

3. SDG&E's "Somewhat Simplistic" Marginal Energy Cost Methodology May Not Be Statistically Valid.

DRA notes that SDG&E's testimony twice discusses correlations[47] but SDG&E does not appear to have used statistical modeling, according to its testimony as summarized above.

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[43] Id, p.DTB-2-B.

[44] Id.

[45] Ex. SDG&E-105, p. DTB-3.

[46] Ex. SDG&E-105, pp. DTB-3 and DTB-4.

[47] Ex. SDG&E-105, p.DTB-3 and Attachment B, p.DTB-2-B.

Of concern to DRA are the following two SDG&E statements:

> *"Then these hourly prices are matched with load based on the assumption that market energy prices are highly correlated with actual loads for 2009-2010." (p. DTB-3)*

And later,

> *While the [SDG&E MEC] approach is somewhat simplistic, it creates a correlation between prices and loads that would be expected and provides an hourly price profile comparable to the CAISO day-ahead market price range for 2009-2010. (Attachment B, p.DTB-2-B)*

There is no indication in SDG&E's testimony or workpapers that it validated the assumption of high correlation using statistical methods; further, one does not "create" a correlation; if it exists in the data, its strength must be determined through statistical methods.

Also of great concern is SDG&E's reliance on the range of hourly loads and the range of hourly LMP prices. Ranges are computed by subtracting the minimum observed value of a distribution from the maximum value. Extreme values of distributions typically have high associated standard errors (uncertainty) and are often discarded as outliers. If the purpose of the computations described in steps 2-4 above is to estimate a relationship between hourly prices and hourly loads, this objective could have and should have been accomplished by standard statistical methods.

SDG&E's analysis lacks statistical validity and should be rejected on that basis.

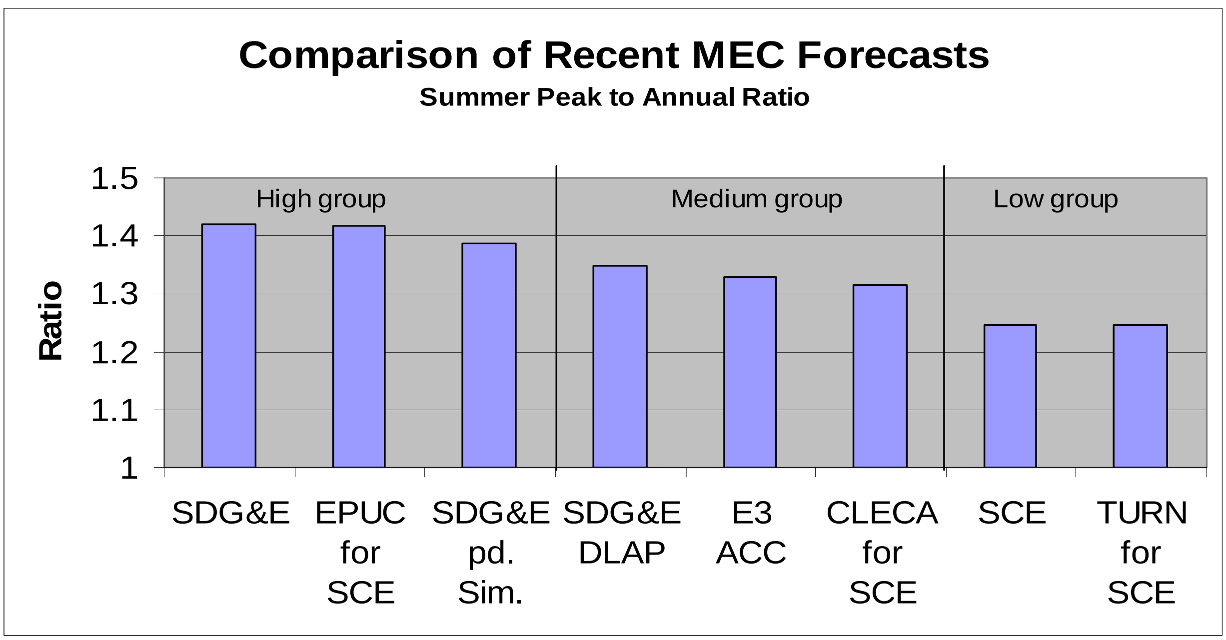
4. SDG&E's Marginal Energy Costs are Significantly "Peakier" than Other Comparable MEC Forecasts; They are Also "Peakier" than Recent CAISO Hourly Energy Prices.

SDG&E's Appendix B compares several MEC forecasts. To that comparison, DRA adds forecasts that were recently prepared by parties to SCE's 2012 GRC Phase 2 proceeding. Figure 2-2 below compares these forecasts with respect to the ratio of summer peak to annual average MEC. The forecasts cluster into three groups, as shown in Figure 2-2.

SDG&E's summer peak to annual ratio is the highest of the comparison group. DRA's recommends using the E3 Avoided Cost Calculator ("ACC") forecast since it is in the middle of the medium group. Of course, the comparison presented here is not definitive, but it does suggest that SDG&E's forecast is out-of-step with the broad consensus of recent forecasts.[48] Of particular note, SDG&E's summer peak ratio is significantly higher than both CLECA's and TURN's (for SCE).

Figure 2-2

Comparison of Recent MEC Forecasts[49]



[48] DRA has excluded SDG&E's "modified PX" case, because the underlying data are too old to be relevant. DRA has also excluded the MEC forecast of the Solar Energy Industries Association for SCE, because, at 1.55, the peak to annual ratio was an outlier to the other forecasts. Finally, DRA did not prepare an independent analysis of MEC shape in A.11-06-007, but accepted SCE's shape profile.

[49] See Appendix for explanation of acronyms contained in Figure 2-2.

5. SDG&E's Proposed MECs Have the Wrong Seasonal Profile.

Yet another indication of flaws in SDG&E's hourly shaping methodology is that SDG&E has the seasonal variation backwards. As shown in Table DTB-1 on p. DTB-6, SDG&E's winter average MEC is higher than its summer MEC. This is not a normal or expected result, as shown by comparison with seasonal MECs based on the E3 Avoided Cost Calculator in Table 2-3.

Table 2-3

Comparison of Seasonal Average MEC Values

	Summer Average MEC	Winter Average MEC
SDG&E Proposed	4.876	4.957
E3 ACC Hourly Factors[50]	5.003	4.872

6. Unlike SCE's Approach in Its 2012 GRC Phase 2, it is Unclear Whether or How SDG&E Accounted for Increased Penetration of Renewable Generation.

In brief, SDG&E created an hourly price profile based on 2009–2010 hourly load and price data, and applied that price profile to the average annual 2013–2014 electric market forward prices.[51]

Price profiles from 2009–2010 cannot be validly applied to 2013–2014 expected prices. Both the generation mix and customer load profiles will have changed significantly between the two periods. Both types of changes are likely to affect the hourly price profiles for 2013–2014. With respect to customer loads, increased penetration of distributed (rooftop) solar generation will flatten the hourly load profile and push the summer peaks to later hours. Changes in the generation mix on the utility side of the meter, including increased utility use of

[50] See DRA Workpapers. These values exclude DRA's proposed 1% ancillary services adder, and average to 4.94 cents, identical within rounding to SDG&E's proposed annual MEC value.

[51] Ex. SDG&E-105, p.DTB-3.

renewable generation that operates more during the on-peak hours, will also flatten hourly MEC values.

These effects were described at some length by SCE in its recent 2012 GRC Phase 2 testimony. SCE explains that it customizes various model inputs to reflect "updated or more accurate information." Among these, SCE utilized "natural gas fuel prices from February 2011," "renewable targets" consistent with the statutory requirement of 33% renewables per California's Renewable Portfolio Standard ("RPS"), and carbon emissions priced at "the 2008 Synapse mid-case."[52]

SCE describes the impact of the RPS on its MEC thusly:

> *…the increase in renewable energy due to the RPS has altered the net load shape served by dispatchable generation. The large amount of solar power projected to come online over this GRC cycle will reduce the daytime net load by a larger proportion than net load during the night-time hours. …Because of the change to the net load shape, which will impact prices, we can expect the on-peak price to decline more than the off-peak price as demand moves down the marginal supply curve.*[53]

DRA finds this SCE testimony both plausible and consistent with economic theory, and agrees with SCE that increased utilization of solar energy could be expected to reduce the spread between on-peak and off-peak marginal energy costs.

SCE also discusses the effect of carbon emissions pricing on MECs. While inclusion of a carbon emissions adder would increase the cost of both natural gas-fired and coal-fired generation,[54] SCE states that:

> *Because coal has significantly higher carbon emissions, compared to natural gas, the application of a carbon cost causes the cost of coal to increase more than natural gas.*

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[52] A.11-06-007, Ex. SCE-02, p. 21. Per Ex. SCE-02, p.16: "The Synapse mid-case starts with a carbon value of $15 per ton (2007$) in 2013 increasing to $53.40 per ton (2007$) in 2030."

[53] Id, p. 23

[54] While coal is not used directly as a fuel source by California utilities, it is used elsewhere in the WECC transmission area.

Thus when coal is on the margin, the cost increase will be higher than if it was natural gas.[55]

SCE states that the difference in carbon intensity between coal and natural gas causes the MEC to increase more in the off-peak periods than in the peak periods, thus further narrowing the spread between on-peak and off-peak MECs.[56]

Implicit in SCE's analysis is that, excluding carbon pricing, coal-fired generation has a lower operating cost than natural gas-fired generation. Therefore, most of the hours when coal is on the margin tend to be off-peak hours.[57] With the addition of carbon pricing, the MECs for those hours when coal is on the margin are substantially increased, and, in some cases, natural gas generation may be dispatched ahead of coal.

Because of carbon pricing as well as increased solar generation, DRA finds SCE's testimony concerning the reduction in the MEC peak to off-peak differentials plausible and consistent with economic theory. In summary, SDG&E's methodology cannot, by its very nature, take into account structural changes in energy generation and consumption that are driving large changes in hourly price profiles between 2009 and 2014.

C. DRA's recommended Marginal Energy Costs

DRA concludes, based on the preceding discussion, that a valid production simulation with forecast 2013–2014 hourly loads and expected generation mix would be required to produce a valid estimate of hourly- and TOU-period MECs. SDG&E has not used such an analysis in developing its MECs.

DRA currently lacks the resources to conduct a full analysis of MECs. However, among the comparison cases SDG&E presents in Appendix B, the profile of marginal costs used in the E3 Avoided Cost Calculator stand out as

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[55] Id, p. 25.

[56] Id, p. 25, see Table I-10.

[57] During peak periods, coal is likely to be fully utilized and natural gas generation will be needed to meet demand.

being the most consistent with recent CAISO hourly price data and with SCE's production simulation results.

DRA therefore recommends to combine the E3 "marginal energy cost profile" in SDG&E's Table 5B-7 with SDG&E's 4.942 cent per kWh annual average MEC plus a 1% ancillary services adder to obtain the TOU period MECs in Table 2-1.

D. Impact of the Renewable Portfolio Standard (RPS) On Marginal Energy Costs

As discussed above, in concept, changes in energy usage can affect the cost of RPS compliance. E3 has acknowledged this effect and has included an RPS component in its avoided cost analyses and calculators. TURN proposed an RPS adder in SCE's GRC Phase 2 proceeding.[58] E3's and TURN's methodologies diverge greatly. Thus, DRA is not prepared to endorse either methodology at this time, and has not included an RPS adder in its proposed marginal costs. DRA may support such an adder if proposed by another party.

IV. CONCLUSION

The Commission should adopt SDG&E's marginal generation capacity costs with the adjustment proposed by DRA to reflect that fact that no additional generation capacity will be needed by California utilities for reliability before 2017. The Commission should adopt SDG&E's proposed annual average marginal energy costs with a 1% addition for ancillary services costs, but use the TOU-period MEC values recommended by DRA, which are more consistent with recent CAISO hourly wholesale electricity price data.

[58] A.11-06-007, testimony of Garrick F. Jones and William B. Marcus, February 6, 2012.

Appendix to Chapter 2

List of Acronyms

Acronym	Full Name
ACC	Avoided Cost Calculator
CAISO	California Independent System Operator
CEC	California Energy Commission
CLECA	California Large Energy Consumers Association
CRR	Capacity Response Ratio
CT	Combustion Turbine
DLAP	Default Load Aggregation Point
E3	Energy And Environmental Economics
EPUC	Energy Producers And Users Coalition
ERI	Energy Reliability Index
LCR	Local Capacity Requirements
LMPs	Locational Marginal Prices
LTPP	Long-Term Planning Proceeding
MEC	Marginal Energy Costs
MGCC	Marginal Generation Capacity Costs
MGCC	Marginal Generation Capacity Costs
NERC	North American Electric Reliability Corporation
OTC	Once-Through-Cooling
RECC	Real Economic Carrying Charge
RPS	Renewable Portfolio Standard
SCE	Southern California Edison
SDG&E Pd. Sim.	Output of SDG&E Production Simulation Model
TOU	Time-Of-Use
WECC	Western Electricity Coordinating Council

CHAPTER 3

MARGINAL DISTRIBUTION & CUSTOMER ACCESS COSTS

LOUIS IRWIN

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CHAPTER 3

MARGINAL DISTRIBUTION AND CUSTOMER ACCESS COSTS

LOUIS IRWIN

I. INTRODUCTION

This chapter addresses SDG&E's marginal distribution costs which are comprised of the marginal distribution demand costs ("MDDC") and the marginal customer access costs ("MCC"). Marginal distribution demand costs are those distribution costs that vary with customers' demand (in kW) on local distribution facilities. Marginal customer access costs are those distribution costs that vary with the number of customers in a given customer class, and do not vary by the customer's usage or peak demand.

SDG&E did not differentiate its marginal distribution demand costs by rate class but rather in two capital cost groups: substations versus feeders and local distribution. The only methodological issue that was of concern to DRA was SDG&E's deviation from the established NERA regression method in the number of historical and forecasted years. After review, DRA has decided to accept SDG&E's MDDC estimates as presented.

DRA finds serious flaws, however, in SDG&E's treatment of its marginal customer costs. For the capital-related components, SDG&E has applied an approach that the Commission has rejected in every litigated marginal cost proceeding since 1993. The approach often is referred to as the "Rental Method." It entails applying a real economic carrying cost "(RECC") to the cost of transformers, service extensions, and new meters ("TSM"). DRA has proposed MCCs using the alternative New Customer Only ("NCO") Method – the method consistently adopted by the Commission since 1993.

SDG&E also erred in its "one-size fits all" treatment of the customer services components of the MCC. SDG&E erroneously attributed these costs identically to the largest and the smallest customers on the SDG&E system, rather than varying them roughly by customer size (as has been done by SCE and PG&E in their recent GRC filings). Because of the magnitude of customer service costs, as presented by SDG&E, this seemingly minor oversight has a dramatic financial impact.

Finally, DRA is concerned that SDG&E's TSM capital cost estimates may not reflect a number of cost exceptions, such as applicant contributions and shared transformers. DRA has proposed modest adjustments to SDG&E's MCCs to reflect these concerns. The aggregate effect of all of DRA's proposals is a 30 to 70 percent decrease across all rate classes when compared to SDG&E's MCC proposals.

II. SUMMARY OF RECOMMENDATIONS

Tables 3-1 and 3-2 list DRA's recommended MDDCs and MCCs and compare them with SDG&E's proposed values. The following paragraphs summarize DRA's recommendations with respect to marginal customer cost methodology.

Table 3-1

SDG&E's and DRA's Recommended MDDCs

Substation Costs ($ per kW-year)	Feeder & Local Dist. ($ per kW-year)
$27.85	$74.06

Table 3-2

MCCs: SDG&E Rental Vs. DRA Recommended (NCO)

Rate Class	SDG&E Rental Method	NCO as Presented by SDG&E	DRA's NCO Model Results	Percentage Difference: DRA vs. SDG&E Rental
Residential	$259.05	212.79	$78.22	-69.8%
Small Commercial	$600.15	$401.48	$292.99	-51.2%
Med./Lg. Commercial & Industrial	$2187.08	$1603.24	$1286.57	-41.2%
Agricultural	$728.19	$405.07	$438.30	-39.8%
Lighting	$19.64	$13.28	$13.12	-33.2%

1. **Treatment of capital (TSM) cost**: The Commission should not depart from its recent precedent. It should continue to adopt the New Customer Only ("NCO") Method and reject the Rental Method. There is no evidence to alter numerous previous Commission findings that the Rental Method overcharges customers for their access equipment.

2. **Customer Service Costs:** Because SDG&E failed to differentiate its customer service charges by account type and to separate out those costs that are truly marginal, DRA proposes to average these costs from the most recent GRC Phase 2 filings of SCE and PG&E. Unlike SDG&E, these utilities relied on previous revenue cycle services ("RCS") studies to separate marginal from non-marginal costs and correctly assign marginal costs by class. Without differentiating these costs by account type, DRA finds that these costs can be on the order of anywhere from 5 times too large to 30 times too small.

3. **Definition for Small Commercial Class**: DRA finds that customer admission into this rate class is too permissive. SDG&E's customer population served under its primary small commercial tariff (Schedule A) contains customers too large to be included in that tariff. About 8 percent of the customers have demands of over 25 kW and over 1,000 customers have demands of over 50 kW. The presence of these larger customers creates an upward bias in the MCC, causing it to be not reflective of the rest of the small commercial class. DRA makes specific short-term and longer-term recommendations in Chapter 6 to address this problem.

4. Adjustments to SDG&E's TSM Costs to Reflect Applicant Contributions: Under the Commissions line extension tariffs (Rules 15 and 16), applicants for new service often are required to contribute to the costs of service connections. SDG&E has stated that, for the Rental Method, which party pays for TSM hook-ups is irrelevant and therefore it does not subtract applicant contributions when allowances are exceeded.[1] In applying the NCO method, DRA attempted to reflect only the true ratepayer cost of new hookups – the cost less contributions from applicants. Applicant contributions should be tracked and deducted. DRA did not have such data but it recommends a 10 percent reduction to SDG&E's TSM costs for all customer classes to account for applicant contributions.

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[1] DRA regards this argument invalid since even the Rental Method should net out applicant contributions given that they can be internalized into the cost of new real estate, which ratepayers pay for in addition to their utility bills. Otherwise, ratepayers could pay for the same costs twice. The Rental Method should be based on only those rate base costs that are included in retail rates.
(continued on next page)

5. Adjustment for Residential Infill:

Some "new" residential customers may connect to existing distribution line transformers, resulting in a reduced cost to connect which is not reflected in SDG&E's analysis. DRA finds that SDG&E's TSM costs are not validated by a study of actual new connection costs. Based on a previous study by PG&E, a small but significant percentage of new residential customer connections utilize existing transformers. SDG&E neither tracks such connections nor makes allowance for them. To correct for the omission of such low-cost customer connection scenarios from SDG&E's MCC analysis, DRA recommends a further 5 percent deduction to residential TSM costs.

6. Future Study Recommendations:

a. SDG&E should undertake a comprehensive study of the costs of new customer connections over at least a 12-month period prior to filing its next GRC. TSM costs should be based on this study and should be net of applicant contributions under Rules 15 and 16 as well as accounting for residential infill.

b. SDG&E should track TSM equipment replacement rates as modified by Smart Meter warranty exclusions.

c. SDG&E should update its RCS studies and use those studies as the basis for its customer service MCC components.

III. DISCUSSION – MARGINAL DISTRIBUTION DEMAND COSTS

The marginal distribution demand costs are those capital and O&M costs associated with the distribution system that vary with customer demand in kW. SDG&E differentiated these costs not by rate class but in two capital cost groups:

(continued from previous page)
Those rate base costs are net of applicant contributions.

substations versus feeders and local distribution. The costs listed in kW-year were $27.85 and $74.06, respectively.

The only methodological issue that was of concern to DRA was SDG&E's deviation from the established NERA regression method in terms of the number of historical and forecasted years. While the established methodology is to use 10 historical and 5 forecasted years, SDG&E presented results using 12 historical and 3 forecasted years. This deviation was made due to a limitation in available forecasted data, with only 3 years being available. DRA requested an alternate scenario where the historical years were scaled back to 10 and the three forecasted years were straight-line extended to 5 years. The results were not substantially different ($26.08 for substations and $70.02 for feeders and local).[2] Therefore, DRA will set aside this alternate scenario and not suggest any changes to the SDG&E proposed MDDCs.

IV. DISCUSSION – MARGINAL CUSTOMER ACCESS COSTS

A. Identification of the Scope of Marginal Customer Access Costs

Marginal customer access costs are the change in costs when the utility adds a single customer. The costs of adding an additional customer include the provision of a new meter, service extension, and transformer ("TSM") along with Operations and Maintenance ("O&M") costs on the TSM. The MCC also includes customer service costs for billing, customer inquiry, and meter reading. For the purpose of marginal cost estimation, the Commission has set the final line transformer ("FLT", the transformer closest to the customer) as the boundary between customer-related distribution and demand-related distribution. The FLT is considered customer access equipment, together with meters and service extensions. Distribution equipment upstream of the FLT is considered demand-related.

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[2] DRA DR 3 Q.1

B. Methodological issues: Rental vs. NCO

1. Historical Background

SDG&E's proposal to use the Rental Method for marginal customer access costs is not supported by any Commission Decision in the last twenty years. Beginning with its decision in PG&E's Test Year 1993 GRC,[3] the Commission has consistently rejected the Rental Method because it found that the Rental Method overcharges customers for the cost of their TSM equipment. Furthermore, in the five decisions since 1992, the Commission has adopted NCO instead of the Rental method.[4] The major reason for its rejection of the Rental Method is that it overestimates the capital cost component of marginal customer costs. Therefore, DRA proposes that the Commission adopt marginal customer costs based on the methodology it has generally adopted for this purpose since 1992 – the NCO method.

[3] Application of PG&E (1992) 47 CPUC 2d 143, 1992 Cal. PUC LEXIS 971, D.92-12-057.

[4] Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal.PUC LEXIS 270, D.96-04-050, FOF 37 and 38.. These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCalGas. While these decisions are old, they are among the most recent Commission decisions to address marginal cost issues. The Commission has generally adopted "black box" settlements of marginal cost issues since 2000.

2. Rental Value, Depreciation and Salvage Value

The Rental Method uses the Real Economic Carrying Costs ("RECC") to annualize the cost of new TSM facilities. This cost is then applied to all customers in a given class, regardless of whether the facilities are actually new or old and fully depreciated. The Rental Method's disregard of economic depreciation creates an overcharge for customer access equipment. This has been noted in several Commission decisions cited herein. Use of the RECC in marginal cost estimation is further discussed in Chapter 1.

Once installed, much of the TSM equipment cost and perhaps all of the labor costs are sunk. While meters and final line transformers ("FLTs") have some salvage value, service extensions have little or none. Likewise, the resale value of intact distribution systems is far less than replacement cost new ("RCN"), but instead invariably reflects a depreciated value.[5]

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[5] See, for example, the following excerpt from D.03-04-032, authorizing a sale of certain PG&E distribution facilities to the Turlock Irrigation District (TID):
"LID [Laguna Irrigation District] argues that <u>PG&E and TID considered only one method of determining the value of the assets, replacement cost less depreciation new (RCNLD), and that other valuation methods might have yielded a ***lower*** and more reasonable sales price.</u> LID therefore asks the Commission to include a condition that provides that the use of RCNLD to value the assets sold to TID shall not be precedent in other cases involving transfers of utility assets. Laguna has been recently involved in litigation with PG&E to condemn certain electric distribution facilities. (Laguna Irrigation District v. Pacific Gas and Electric Company, Kings County Superior Court No. 99 C 052.) Laguna is therefore concerned that the valuation method here may be precedent in its pending litigation. We agree with PG&E that the courts will assess whether evidence regarding the valuation of utility assets in Commission proceedings should be considered in the condemnation proceedings, as well as the weight to be given Commission decisions pursuant to California law. <u>LID does not oppose the sales price and has presented no evidence to show that the use of the RCNLD method of valuation has created an unfair or unrealistic price for the assets being sold to TID</u>, or that another method of valuation would have resulted in a different price. <u>Previous Commission decisions have found that a sales price for utility assets based on RCNLD, when negotiated between the parties in arms-length transactions, is fair and reasonable. We therefore approve the sales price here based on RCNLD.</u> However, we recognize that RCNLD is only one method of valuation, and we may consider different valuation methodologies in other cases." (D.03-04-032, mimeo, pp. 42-43, emphasis added).

Given these facts, it is clear that this capital cost needs to be depreciated in value, which the Rental Method fails to do.

Thus the Commission has consistently found that the Rental Method overstates costs. For example, in 1996, the Commission made the following Findings of Fact:[6]

> 37. The Rental Method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market.
>
> 38. Under the Rental method, and the associated RECC assumptions, Edison's marginal customer costs exceed the cost of hooking up new customers, installing replacements and covering the variable expenses for all customers….

SDG&E has presented no evidence or analysis suggesting that the Commission should reach a different conclusion with regard to the Rental Method in this proceeding. Therefore, DRA requests that all future GRC Phase 2 Applications and updates contain an updated, fully integrated MCC model based on the adopted NCO methodology.

C. Customer Service Costs

Customer services costs include the costs of meter reading, billing, handling customer inquiries, and related costs. These costs are expenses that are unrelated to TSM equipment and do not vary with the choice of Rental or NCO methodology.

DRA takes issue with SDG&E's estimates of customer service costs on several key points. In its testimony, SDG&E states that it relied on FERC Form 1 data. DRA concludes that SDG&E's customer service marginal costs are too

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[6] Application of SCE (1996) 65 CPUC 2d 362, 1996 Cal.PUC LEXIS 270, D.96-04-050, FOF 37 and 38.. These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCalGas. While these decisions are old, they are among the most recent Commission decisions to address marginal cost issues. The Commission has generally adopted "black box" settlements of marginal cost issues since 2000.

high because it has failed to eliminate costs that are not truly marginal[7]. For customer service costs, non-marginal costs might include expenses associated with maintenance of computer networks, software development, billing facilities and related overhead. Such costs are unlikely to vary with small changes to the numbers of customers served.

SDG&E also failed to make any distinctions between different customer classes except for excluding certain costs for streetlight customers because they are unmetered. SDG&E's testimony states that, with respect to customer services cost, FERC indicated "no difference between rate schedule/classes, except in the case of unmetered schedules."[8] In contrast, as described below, PG&E's and SCE's recently filed marginal costs for customer services are sharply differentiated by rate class and are far more credible than SDG&E's single value of $160.43 for both small and large customers. Both PG&E and SCE relied upon updated Revenue Cycles Services (RCS) cost studies in determining the customer services components of the MCC.[9]

Examination of the actual customer service marginal costs proposed by SDG&E is revealing. SDG&E's customer service costs for residential accounts ($160.43) are over 60 percent of the total customer access marginal costs ($259.05).[10] Customer service costs are not typically such a huge proportion of the MCCs. As shown in Table 3-3 below, SDG&E's results are completely uncorrelated with the corresponding costs reported by PG&E and SCE.

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[7] FERC Form 1 data typically includes both marginal and non-marginal costs.

[8] SDG&E Exhibit -106-R, March 30, 2012, RME-9, lines 1- 3.

[9] See, for example, PG&E, Revenue Cycle Services Cost Study, A.97-11-004, March 19, 1998.

[10] SDG&E Exhibit 106-R, March 30, 2012, Table RME-03, -. RME-10, SD&E WP Customer Marginal Cost, tab NCO-Res, row 37.

Table 3-3

Comparative Customer Service Costs

1	**Rate Class**	**PG&E Scaled to 2012$**[11]	**SCE $2012**[12]	**PG&E/SCE Average**	**SDG&E $2012**[13]	**Difference SDG&E / Average**
2	**Residential**	31.66	35.25	33.46	160.43	379 %
3	**Small Commercial**	97.68	35.49	66.59	160.43	141 %
4	**Medium Commercial**	531.99	140.51	336.25	160.43	-52 %
5	**Lg. Commercial**	8,663.57	1,074.54	4,869.06	160.43	-97%
6	**Small Ag.**	170.85	104.33	137.59	160.43	17 %
7	**Lg. Ag.**	339.19	755.75	547.47	160.43	-71 %
8	**Ratio High Costs to Low**	274 to 1	30 to 1	146 to 1	1 to 1	
9	**Street Light**	46.33	34.38	40.36	5.84	-86 %
10	**Weighted Avg Including Streetlight**	71.49	40.88	60.98	159.81	162%

In line 8 of Table 3-3, it shows the ratio of high to low charges for the all rate classes except for streetlights in lines 1 through 7. For SDG&E this ratio is 1 to 1, meaning that there is no differentiation. Whereas, for the other major California electric utilities, these costs are highly differentiated. This cost ratio is 274 to 1 and 30 to 1 for PG&E and SCE, respectively. Stated yet another way, SDG&E's flattening of these costs creates costs for the Residential class that are

[11] PG&E 2011 GRC, Application 10-03-014, March 22, 2010, Workpapers, WP 7-3. 2011 dollars scaled up by the SDG&E escalator for 2009 to 2102 (1.0717). Since this escalator was for three years, DRA divided by three to approximate a one year escalator from 2011 to 2012.

[12] SCE 2012 GRC Application 11-06-007. Phase 2 WP Oct2011 Update, MCCR tab.

[13] SDG&E GRC, Application 11-10-002, March 30, 2012 Second Revised WP, Chapter 6, MCC..

five times the SCE / PG&E average. For Large Commercial – Industrial customers, they are one thirtieth of the SCE / PG&E average. That disparity without cause is not supportable. Though both SCE's and PG&E's costs are highly differentiated, they are very similar for the Residential rate class. Indeed, the costs for these two IOU's are within $2 of each other ($35.25 vs. $33.46, line 2). That represents a high degree of consensus.

Furthermore, casual observation does not support SDG&E's undifferentiated approach to these costs. It is clear that large commercial accounts will have dedicated account representatives, whereas Residential and Small Commercial do not. This would increase the costs for Large Commercial - Industrial accounts as is illustrated in the PG&E column of this table (line 5).

For SDG&E, when street lighting is included, the system average customer service costs dip slightly to $159.81 (line 10). But this is substantially higher than for PG&E ($71.49) or SCE (40.88). So we also see that for SDG&E system average Customer Service Costs are 162 percent higher than the simple average of SCE and PG&E. This suggests the inclusion of a number of costs that are non-marginal.

A third issue, that is not discussed by SDG&E, is the need to capture benefits related to AMI as offsets to customer services costs. These credits pertain to avoided meter reading costs as well as advanced grid and account management information that AMI can provide. For instance, in the PG&E GRC, these benefits, averaged across all classes were estimated at $22.15 per account.[14] Overlooking these credits also leads to MCC overestimation on SDG&E's part.

Because SDG&E has not provided the necessary information for an accurate estimate of SDG&E-specific customer service MCCs differentiated by customer class, DRA proposes that an average of the SCE and PG&E costs, by

[14] PG&E A.10-03-14 Exhibit 2 WP, June 2010, _Results_CMC_Cust_MC_Summary, tab RCS-Breakout, column F.

rate class, be used for SDG&E's customer service costs. While only a proxy for SDG&E-specific costs, DRA's proposal is a vast improvement over the SDG&E proposal in terms of accuracy. These costs are scaled more appropriately and are differentiated by type of account. For Residential customers, it reduces the costs over $125 customer / year while the change for Small Commercial customers is nearly $100 customer / year. For Residential customers, this $125 difference is nearly 50 percent of SDG&E's proposed costs of $259.

To avoid rate shock, however, DRA proposes accepting the SDG&E proposed NCO Customer Service Rate for Street Lighting ($5.84 / customer-year). If the PG&E / SCE average were used instead ($40.36 / customer-year), as shown below (Table 3-1, line 7), these costs would increase about seven fold. Using SDG&E's NCO proposal for Street Lighting will not have a dramatic effect on the revenue allocation and rate making for the others classes.

D. Implementation of NCO Model

Given the issues with the Rental Method and the Commission's stated preference for the NCO method, DRA now turns to NCO implementation issues. Although SDG&E has included an NCO scenario in its Workpapers, DRA still takes exception to some of the modeling choices that were made.

1. Customer Growth Rates

One criticism of the NCO Method is that, in economically volatile times, growth rates by rate class can be quite disparate. During recessions, these growth rates can even be negative. In these situations, the NCO Method arguably does not produce useful results. DRA proposes to address this problem by applying the historical residential growth rate (2007 through 2011) to both the residential and commercial classes to obtain a forecast of new customers. In this case, the recent historical residential growth rate is a modest 0.57 percent. This approach seems reasonable because the growth rates for the commercial classes will be correlated to the residential growth rate in the long run.

In contrast, SDG&E has developed a forecast of customer growth rates rather than using historical values. Its NCO customer count forecast for these classes is much higher than historical values, ranging from 1.11 percent for Residential to 2.78 percent for Commercial Industrial.[15] Given the current economic climate, these SDG&E forecasts seem overly optimistic.

For the Agricultural and Street Lighting growth rates, DRA took a different approach. The NCO forecast based on the same five year historical record (2007 through 2011) was negative for these rates. For the Agricultural and Street Lighting rates, DRA has elected to assume zero customer growth.

2. TSM Replacement Rates

SDG&E uses 1.5 percent as its equipment replacement rate. DRA's accepts this rate as it seems reasonable. In conversation with the SDG&E witness, Cynthia Fang, DRA learned that this was the same replacement rate as was used in the previous GRC.[16] While that provides some credence, there has been a sharp increase in the amount of newly installed meters since the last GRC owing to the deployment of Smart Meters, and most of this equipment may still be under warranty. However, meters are only a fraction of the total TSM costs (perhaps 15 percent or 20 percent). Therefore, the impact of new meters would most likely be meaningful, but not overly dramatic.

Therefore, DRA does not choose to challenge this modeling assumption at this time. Replacement rates, however, do have a significant effect on the total MCC. Accordingly, DRA recommends that the Commission requests that these costs be tracked for the next GRC with special consideration of both warranty coverage and the average equipment age on the replacement rate.

[15] DRA WP, tab Input, column AA.

[16] May 9, 2012.

3. Applicant Contributions to TSM Costs

Applicant contributions occur where the cost of a new customer installation exceeds the line extension allowance under Rules 15 and 16. This is a frequent occurrence in low-density, higher cost residential developments, because residential allowances are set at a fixed amount per dwelling unit, regardless of the actual cost. Developers must often make substantial contributions to the cost of facilities needed to serve new residential subdivisions. When the applicant pays a portion of such costs, clearly the ratepayers have less cost responsibility and the true revenue requirement is less. This is a fact that SDG&E did not account for in its Rental Method calculation.[17]

Since SDG&E has not tracked developer or applicant contributions, DRA recommends an across-the-board decrease of 10 percent in the TSM component of MCC. This estimate is probably conservative because a 2003 PG&E study found that applicants were paying, on average, 22 percent of the costs.[18] This 10 percent reduction would produce substantially less than an overall 10 percent reduction to the MCC as it is only applied to the capital TSM costs and not customer account services.

4. Residential TSM Costs and Infill

DRA's analysis also revealed that SDG&E is not tracking the difference between residential customers receiving an entirely new connection and those whose connections could be described as "in-fill" in an existing neighborhood.[19] The main cost differentiation is that in-fill customers would not require a transformer if they can share an existing one with existing customers. The connection cost discount for those infill customers can be as much as 60 percent.[20]

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[17] DRA DR 12, Q. 1c.

[18] Cited in SCE GRC II A.11-16-007, DRA DR 2, Q. 9, March 2, 2012.

[19] DRA DR 8, Q. 2.

[20] DRA WP, tab NCO-Res, transformer costs as a percentage of total in PVRR form, cells K25 / K29.

(continued on next page)

DRA recommends that SDG&E conduct a comprehensive study of its customer connection costs to ensure that the variability of its customer connection costs is accounted for in its next MCCs. For now, the expedient adjustment would be 5 percent reduction for residential MCCs. This adjustment is only applied to the residential class since customers in other classes tend to receive dedicated transformers rather than sharing them with other customers. The cost savings from an "in-fill" situation would be significantly less if it does not involve the avoided cost of a transformer. Like the adjustment for applicant contributions, this adjustment is only applied to the capital TSM costs and not to the customer account services. The overall effect is, therefore, far less than 5 percent.

5. Maximum Annual Demand Subclassifications for Small Commercial

The maximum demand limit for eligibility for SDG&E's small commercial rate is porous. All a customer needs to do to qualify is to be below a maximum demand of 20 kW for any one of twelve consecutive months.[21] Therefore, many otherwise large accounts, which have any degree of seasonality in their demand, even for as little as one month, can qualify for this rate.

In contrast, SCE customers cannot remain on its small commercial rate (GS-1) if they have exceeded, or are expected to exceed, a maximum monthly demand of 20 kW for any three months in the test year.[22] While over three-fourths of SDG&E's small commercial accounts have a maximum annual demand of less than 12 kW, there are over 1,000 accounts with a maximum annual demand over 50 kW. These large demand accounts range from 50 kW up to 750 kW in maximum annual demand.

(continued from previous page)

[21] DRA DR 13, Q. 1.

[22] SCE.com, tariffs.

The TSM costs for these large demand accounts tend to be significantly higher. Ideally, accounts with a maximum annual demand greater than 20 kW should be moved to the Medium and Large Commercial rate class. To further inform the impact of this issue on the revenues allocated to the Small Commercial rate class as well as rates for this class, DRA estimated the MCC for the customers with maximum annual demand smaller and greater than 20 kW separately. The impact on revenue allocation is discussed in DRA's Chapter 4 and the impact on rate design in Chapter 6.

Though SDG&E provided the data in its workpapers to allow calculation for the TSM costs, the O&M costs for the Schedule A are undifferentiated between small and large customers. SDG&E typically did differentiate these costs by subclass within other customer classes, with one other exception.[23] However, a second issue is that, even when SDG&E did differentiate these costs in other classes, it did not weight these costs correctly. DRA believes that the ideal weighting would be by the product of TSM costs times the new and replacement customer forecast.

SDG&E's testimony states that SDG&E did in fact perform such an allocation. It states:

> *"SDG&E then allocates customer related O&M costs to the various rate schedules by using a factor derived from each schedule's percentage of the grand total of estimated TSM." (RME-9)*

But, evidently, SDG&E's model is at variance with its testimony. This oversight in the SDG&E model has been corrected by DRA for the Schedule A, Small Commercial, O&M Costs.

Results of this analysis are presented below in Section E. Discussion is deferred to that section since other DRA proposals will also affect the outcome for Small Commercial.

[23] SDG&E MCC WP, May 9 2011, Schedule AD, General Service Demand Metered - part of the tab, Comm – Ind class.

E. Aggregate MCC Results

The overall impact of DRA's adjusted NCO MCCs are shown above in Table 3-2. The results are presented for the five major rate classes. As can be seen in the aggregate results, DRA's results for each class are 30 percent (Street Lighting) to nearly 70 percent (Residential) less than SDG&E's results. One of the largest contributing factors to this decrease was DRA's proposal on Customer Service Costs. DRA found SDG&E's cost estimates to be excessive, and they represent a significant portion of the overall MCC costs for the smaller customers.

Turning specifically to the Small Commercial MCC, the DRA proposed value is $292.99, compared to SDG&E's estimate of $600.15. Within this class, Schedule A is the most heavily populated subclass with over 93 percent of the accounts.[24] For this subclass, the MCC for customers with a maximum annual demand of less than 20 kW is $211.75 per customer-year, while the MCC rises nearly six fold to $1,262.37 per customer-year for those customers over 20 kW in maximum annual demand. These results are comparable to those in SCE's recent GRC for the Small and Medium rate classes.[25]

MCC for the entire the Small Commercial rate class, excluding those customers on Schedule A that are over 20 kW, is only $205.03.[26] Therefore, DRA's recommendation for Small Commercial would have been an additional 30 percent lower if these larger customers were separated out and addressed separately.[27] This issue is further addressed in Chapter 6, on small commercial rate design.

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[24] SDG&E MCC WP Second Revised-Final, tab NCO – Small Comm, cell D31 / H31.

[25] SCE 2012 GRC, A.11-06-007, June 6, 2011, Table I-15, GS-1, General Service (single phase meters) is $163.53, about $50 less than the SDG&E proposal of $211.75 above. GS-2 General Service Demand (single phase meters) is $1127.77 or a little over 10 percent less than the finding of $1262.37 stated above.

[26] Ibid. cells B40, C40, H45.

[27] $205.03 / $292.99 = 70 percent.

V. CONCLUSION

DRA has reviewed SDG&E's MDDC and MCC costs in this chapter. For marginal distribution costs DRA accepts SDG&E's proposal. For the MCC, however, DRA does not accept SDG&E's proposals and proposes its own major revisions to SDG&E's stated MCCs. First, DRA rejects SDG&E's use of the Rental method, which runs counter to the strong Commission precedent established over the last two decades. DRA instead uses the CPUC preferred New Customer Only method. Second, DRA has shown that SDG&E's proposal for Customer Service Costs is excessive and that the costs were not differentiated by rate class – a shortcoming that also affected some of the O&M costs.

DRA also identified several other instances where the SDG&E calculations are not adequately supported by data, and recommends that SDG&E perform key studies of its customer costs before its next GRC. DRA's MCC recommendations are 33 percent to 70 percent lower than SDG&E's proposals. If adopted, they will create significant benefits for the equity and accuracy of SDG&E's rate design.

CHAPTER 4

REVENUE ALLOCATION

LEE-WHEI TAN

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CHAPTER 4

REVENUE ALLOCATION

LEE-WHEI TAN

I. INTRODUCTION

This chapter addresses DRA's proposals for allocating generation, distribution, and a variety of miscellaneous revenue responsibilities to customer groups. Below, DRA provides its analysis of SDG&E's proposals and explanations of DRA's recommendations.

II. SUMMARY OF RECOMMENDATIONS

In this GRC Phase II proceeding, DRA recommends using a marginal cost-based revenue allocation methodology consistent with the Commission's long standing policy and economic efficiency objective[1]. This methodology is applied to generation and distribution revenue requirements, which constitute 76.5 percent of the overall revenue requirement.[2] DRA's adjustments to SDG&E's marginal cost estimates in Chapters 2 and 3 are incorporated into its revenue allocation.

The miscellaneous revenue responsibilities include a variety of programs, including energy efficiency ("EE"), demand response ("DR"), and the California Alternative Rates for Energy ("CARE"). DRA proposes using a generation revenue allocator,[3] which SDG&E calls a "commodity" allocator, for EE and DR programs. SDG&E has proposed to freeze their current allocations instead of advocating any specific allocator to those programs.

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[1] Though DRA is given legislative responsibility to mainly represent residential and small business customers for revenue allocation and rate design issues, DRA believes it is a good public policy to mitigate significant rate increase for any customer class. Therefore, DRA also supports the concept of applying a cap on the rate changes to maintain rate stability.

[2] SDG&E consolidated model, tab "Class AVG Rev Adj Y1"

[3] Generation allocator is to allocate cost based on the proportion of each class' marginal generation revenue (which include marginal energy cost revenue and generation capacity cost revenues) relative to the total system generation revenues.

DRA allocates CARE shortfalls through equal cents per kWh pursuant to Public Utilities Code (PU Code) 327 (a) (7). In contrast, SDG&E allocates a portion of the CARE shortfall to all customer classes using equal cents per kWh a portion only to non-CARE customers within the residential class. Going forward, SDG&E should allocate all CARE costs, including the CARE shortfall, using equal cents per kWh, to all classes to conform with PU Code 327 (a) (7). Also, SDG&E should calculate the CARE shortfall as the difference between CARE and non-CARE residential rates times CARE sales.

All of the aforementioned changes contribute to the final allocation and to how DRA's proposed rates deviate from that of SDG&E. In summary, DRA recommends the Commission adopt:

1. DRA's marginal costs to allocate revenue responsibilities;
2. Use of a generation revenue allocator for EE and DR programs (including dynamic pricing implementation).
3. Allocation of the CARE shortfall by equal cents per kWh.

Table 4-1 below is DRA's proposed class average rates in contrast to those of SDG&E's:

		SDG&E		**DRA**[4]	
	Current Total Rate (¢/KWhr)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)	Proposed Total Rate (¢/KWhr)	Total Rate Change (%)
Residential	17.612	17.373	-1.36%	**16.407**	**-6.84%**
Small Commercial	17.045	18.032	5.79%	**17.714**	**3.92%**
Med&Lg C&I	13.645	13.808	1.19%	**14.562**	**6.72%**
Agriculture	16.563	16.023	-3.26%	**16.207**	**-2.15%**
Lighting	14.653	14.246	-2.78%	**14.448**	**-1.40%**
System Total	15.449	15.539	0.58%	**15.536**	**0.56%**

[4] As stated in footnote 1, DRA would support a capping proposal that would mitigate significant rate increases.

III. DISCUSSION

A. Marginal Cost Revenue Allocation

Revenue allocation is a process of assigning to each customer class a portion of the utility's revenue requirement. The Commission has applied marginal cost-based revenue allocation since the late 1970s. The process starts with calculating marginal costs for each utility function (generation and distribution).[5] Then the cost responsibility is assigned to classes based on the proportion of each class' marginal cost revenue relative to the total system marginal cost revenues.[6]

In D.97-08-056, the Commission adopted a practice of allocating the revenue requirements of each individual function separately. Thus, the corresponding revenues are allocated on an unbundled basis using the separate marginal cost revenues for each function. This method determines each customer class' revenue responsibility by function based on the marginal cost revenue assigned to the class. The latter then is scaled up or down to match the authorized revenue requirement for each of the functions. The result is called an equal percent marginal cost ("EPMC") allocation.[7]

The marginal cost revenue is calculated by taking the product of the functional marginal cost and the marginal demand measures ("MDM"). Marginal costs include marginal energy, generation capacity, distribution demand, and customer access costs. MDMs include measurement of each class' energy consumption, demand during the system peak, the non-coincident peak, and the number of customers.

In this proceeding, SDG&E proposes to continue using the same functional marginal cost allocation, where the commodity (or generation) and distribution

[5] Since the electric industry restructuring of the late 1990s, most transmission is regulated by Federal Energy Regulatory Commission (FERC).

[6] A "marginal cost revenue" is the revenue that would be produced if each customer were charged the marginal cost.

[7] Transmission revenue is set separately by FERC.

functions are allocated separately using the EPMC method,[8] and DRA concurs. SDG&E also is proposing to allocate ongoing Competition Transition Charge ("CTC") revenue requirements based on the top 100 hours allocation methodology as adopted in D.00-06-034. DRA takes no issue with SDG&E's CTC allocation proposal.

B. Marginal Commodity Cost Revenue

There are two generation-related cost elements. The marginal commodity energy cost refers to the incremental cost of adding one additional unit (i.e. kWh) of energy consumption on the electrical system. The marginal commodity capacity cost measures the incremental cost that an incremental megawatt ("MW") of demand imposes on the system. These marginal costs are discussed in Chapter 2 of DRA's testimony. Mathematically, the marginal commodity cost revenues can be expressed below:

Σ Marginal commodity energy cost revenue $_i$ = Σ Marginal energy cost by time of use ("TOU") period * energy consumption in each TOU period by customer class i

Σ Marginal commodity capacity cost revenue $_i$ = Σ Marginal capacity cost * class i's MW demand during the system's top 100 hours demand

C. Marginal Distribution Cost Revenue

Distribution marginal costs are associated with providing customer access to, and accommodating customer demand, on the distribution system. DRA presents marginal customer access cost proposals that differ from those of SDG&E, as explained in Chapters 3. DRA uses the new customer hookup ("NCO") method, while SDG&E uses the "rental" method. In the NCO method, the marginal demand measure is the number of new customers, whereas in the rental method, it is the total number of customers. Again, the marginal distribution costs are expressed as follows:

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[8] SDG&E proposes to allocate its CPUC-jurisdictional revenue requirements for distribution and generation services based on its marginal costs. (Ex. SDG&E-103, p.WGS-1.)

Σ Marginal distribution demand cost revenue $_i$ = Σ Distribution demand marginal cost * Class i's non-coincident peak demand[9] * effective demand factor[10] ("EDF")

Σ Marginal customer cost revenue $_i$ = Σ Number of customers for customer class i * TSM[11] costs[12]

Because of the marginal cost differences, DRA's marginal cost revenues are different from SDG&E's.

IV. DEMAND RESPONSE PROGRAMS AND AMI-RELATED COSTS SHOULD BE ALLOCATED BASED ON A GENERATION REVENUE ALLOCATOR

SDG&E has decided to retain the current allocations for EE and DR programs.[13] D.12-04-045 shows that SDG&E's DR programs include interruptibles, capacity bidding, peak time rebate, and load shifting programs.[14] These programs are clearly designed to reduce either energy consumption or capacity needs, and hence their costs should be allocated based on generation revenues. EE has the same characteristics as the aforementioned DR programs. Therefore, DRA proposes that both DRs and EEs are allocated based on generation EPMC.

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[9] Non-coincident peak is the maximum demand of a customer class regardless of when the system peak occurs.

[10] SDG&E describes the distribution demand measure (DMDM) as the estimated class loads at circuit and substation peak levels. (WGS-3) SDG&E also explains that it has adapted Southern California Edison's (SCE's) method to determine the class billing determinants (or demand measures). SDG&E explains that this process involves in estimating the class contribution to the circuit/substation peak, which SCE called the effective demand factor ("EDF"). So, EDFs will vary by type of customer and by the voltage level of the circuit. (A.11-10-002, Ex. SDG&E-102, CF – 11- I.)

[11] TSM refers to transformer, service drop, and meter, which are the facilities that provide customer access to the system and grouped as customer costs.

[12] Even though DRA's NCO uses one time total hook-up costs for new customers, the numbers are converted to per customer as comparable to the rental in the model.

[13] Re SDG&E response to UCAN data request 14, Q.01.

[14] D.12-04-045, p. 33.

DRA also notes that SDG&E has a dynamic pricing implementation cost settlement pending the Commission's resolution.[15] The settlement provides that parties will present their preferred allocation proposals for these implementation costs in this GRC Phase 2 case.[16] Once these costs are approved in rates, DRA recommend that they also be allocated using a generation allocator. Both PG&E and SCE have recognized that costs associated with implementing dynamic pricing rates should be assigned to customer classes based on generation allocators.

For instance, in a previous AMI proceeding, PG&E characterized dynamic pricing-related Demand Response benefits as related to generation capacity and energy costs:

> *Demand response impacts refer to the change in customer-specific peak demand and energy use, by rate period,* ***resulting from time-varying tariffs.*** *In this chapter, the term "financial benefits" means the monetary value of reductions in both capacity and energy that flow from changes in peak demand and energy use induced by new tariffs…. This chapter discusses the financial benefits associated with* ***avoided generation capacity and changes in the total cost of energy needed to meet demand)***[17].

On the Commission's website[18], the Commission provides explanation of the benefits of smart meters:

- **Provides customers with greater control over their electricity use when coupled with time-based rates,** increasing the range of different pricing plans available to customers and giving them more choice in managing their electricity consumption and bills.

Smart Meters enable a utility to measure a customer's electricity usage in hourly increments.

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[15] A.10-07-009, parties have reached a settlement to approve SDG&E for $93 million dynamic pricing implementation costs.

[16] Settlement Agreement, terms and condition 11. Filed in A.10-07-009 on June 20, 2011.

[17] PG&E, A.05-06-028, Exh.PGE-4, Ch. 5, pp .5-1, 5-2, emphasis added.

[18] http://www.cpuc.ca.gov/PUC/energy/Demand+Response/benefits.htm

If a customer elects to participate in time-based rates offered by the utility, they have the opportunity to lower their electricity demand during "peak" periods (the peak period for most utilities are summer afternoons) and potentially save money on their monthly electric bill.

- **Helps the environment by reducing the need to build power plants, or avoiding the use of older, less efficient power plants as customers lower their electric demand.**

This is beneficial for all utility customers because the costs of building new power plants or relying on older, less-efficient power plants are eventually passed on to customers in retail rates. Building power plants that are necessary only for occasional peak demand is very expensive. A more economical approach is to enable customers to reduce their demand through time-based rates or other incentive programs.

The identified benefits described above clearly links time-varying rates, which includes dynamic pricing, with generation capacity and energy consumption or the avoidance of them. Therefore, DRA recommends that SDG&E apply the same cost-causation principle to assign the dynamic pricing implementation costs based on generation allocator.

V. CARE SHORT FALL COSTS SHOULD BE ALLOCATED BASED ON EQUAL CENTS PER KWH

PU Code 327 (a) (7) states:

> *For electrical corporations and for public **utilities** that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatthour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008.*

The above requirement was codified when Senator Bill 695 was approved in October 2009. DRA notes that SGD&E is not completely following the above-stated statutory requirement to allocate the costs of the CARE program on an equal cents per kWh basis. SDG&E reflects the CARE shortfall costs in two places in its revenue allocation model, in the CARE surcharge and in the Total Rate Adjustment Component (TRAC). SDG&E properly allocates the former costs on an equal cents per kWh basis to all classes of customers subject to the CARE surcharge. However, SDG&E indicates that the other CARE costs in TRAC remain within the residential class, meaning that they are allocated within the residential class only.

To comply with PU Code 327(a)(7) DRA recommends that all CARE costs be calculated and allocated equal cents per kWh to all classes. Total CARE costs would include administrative costs, CARE balancing account amortizations, and the CARE short fall. The CARE short fall should be calculated as the difference between the non-CARE rates and the CARE rates times the CARE sales. This is how CARE costs currently are calculated by PG&E and SCE, and SDG&E should do the same to comply with state law.

VI. CONCLUSION

DRA recommends that revenue allocation be based on DRA's proposed marginal costs. DRA further recommends that DR as well as EE programs and dynamic pricing costs be assigned to classes based on a generation marginal cost revenue allocator. Finally, CARE costs should be allocated based on equal cents per kWh pursuant to PU Code 327 (a) (7).

CHAPTER 5

RESIDENTIAL RATE DESIGN

DEXTER KHOURY

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CHAPTER 5

RESIDENTIAL RATE DESIGN

DEXTER KHOURY

I. INTRODUCTION AND SUMMARY

This chapter summarizes the residential rate design recommendations of the Division of Ratepayer Advocates ("DRA") for San Diego Gas and Electric Company's ("SDG&E") General Rate Case ("GRC"), Phase II (A.11-10-002). DRA's rate design recommendations are based on DRA's revenue allocation proposals, which are explained in chapter 4.

DRA recommends:

1. SDG&E's proposal to introduce a residential basic service fee or customer charge of $3 per month should be denied on legal and policy grounds.
2. SDG&E's proposal to consolidate Tier 3 and tier 4 should be denied.
3. A New Cap on CARE tier 3 rates of a maximum of 18 cents per kWh should be adopted until SDG&E's next General Rate Case.
4. SDG&E's proposal to clearly identify total residential rates should be adopted.

Table 5-1 shows SDG&E's current rates, SDG&E's proposed rates, and DRA's proposed rates for bundled residential customers. DRA's proposed residential rates are lower than both SDG&E's current and proposed rates.

TABLE 5-1
PROPOSED RESIDENTIAL RATES FOR SDG&E

	Current Rates	SDG&E Proposed	DRA Proposed[1]
Schedule DR			
Customer Charge per month	$0.00	$3.00	$0.00
Summer Tier 1	0.14334	0.13277	0.14334
Summer Tier 2	0.16580	0.16580	0.16580
Summer Tier 3	0.25694	0.27515	0.23273
Summer Tier 4	0.27694	0.27515	0.25273
Winter Tier 1	0.14334	0.13277	0.14334
Winter Tier 2	0.16580	0.16580	0.16580
Winter Tier 3	0.23974	0.24035	0.20220
Winter Tier 4	0.25974	0.24035	0.22220
Schedule DR-LI			
Customer Charge	$0.00	$3.00	$0.00
Summer Tier 1	0.09946	0.09111	0.09946
Summer Tier 2	0.11608	0.11608	0.11608
Summer Tier 3	0.17545	0.17768	0.14375
Winter Tier 1	0.09946	0.09111	0.09946
Winter Tier 2	0.11608	0.11608	0.11608
Winter Tier 3	0.16405	0.14984	0.11932

[1] DRA's proposed rates would likely increase if a cap on the revenue allocation is implemented in settlement talks.

II. SDG&E'S PROPOSALS

A. Summary of SDG&E's Residential Rate Design Proposals

SDG&E proposes three significant changes to residential rate design:

1. Customer Charge

SDG&E proposes to introduce a residential customer charge, which it refers to as a "basic service fee" ("BSF"). Its testimony states:

> *SDG&E proposes to replace the existing minimum bill charge with a modest monthly BSF of $3, with the residual customer costs recovered through a volumetric ($ per kWh) distribution rate. (Chapter 2, p. CF-8, lines 13 to 14)*

It further states:

> *For residential customers on tiered rate schedules (specifically schedules DR, which includes DR-LI, and DR-TOU), the introduction of the monthly BSF will reduce the residential Tier 1 energy rates to ensure compliance with the rate cap required by Section 739 of the California Public Utilities Code. (SDG&E Testimony, Chapter 2, p. CF-8 line 18 to p. CF-9 line 1)*

2. Consolidation of Tier 3 and Tier 4

SDG&E proposes to move to a residential three-tier rate design by consolidating tier 3 and tier 4. Its testimony states:

> SDG&E's standard residential rates have a 4-tiered rate structure with a 2 cent differential between tiers 3 and 4. With the introduction of the BSF component for residential customers, SDG&E proposes to simplify by consolidating tiers 3 and 4 to a 3-tiered rate structure. (SDG&E Testimony, Chapter 2, p. CF-23, lines 12 to 15)

3. Freeze on CARE tier 3 rates

SDG&E proposes to remove the freeze on CARE tier 3 rates that has been in place since D.09-09-036 adopted a residential rate design settlement in SDG&E's 2009 RDW (A.08-11-014). It states:

SDG&E proposes to remove the cap on residential CARE tier 3 rates on a going-forward basis to eliminate a false price signal resulting from legacy settlements. (SDG&E Testimony, Chapter 2, pp.23 – 24)

III. DISCUSSION

A. SDG&E's proposal to introduce a residential customer charge should be rejected on legal and policy grounds

DRA opposes SDG&E's proposal to create a $3 per month residential customer charge. It recommends that the Commission reject it for both legal and policy reasons. These are discussed below.

1. SDG&E's proposed residential customer charge violates Public Utilities Code 739.9 (a) and 739.1(b) (2)

SDG&E's proposed residential customer charge closely resembles a similar proposal Pacific Gas and Electric Company ("PG&E") made in its 2010 GRC Phase II Application. The Commission recently examined and rejected that proposal in Decision ("D.")11-05-47. The Commission also denied the joint application for rehearing filed by PG&E, Southern California Edison Company ("SCE"), and Kern County Taxpayers Association ("Kern Taxpayers")[2] of that Decision.

Like PG&E's rejected proposal, SDG&E's residential customer charge violates SB 695 rate protections for tier 1 rates for residential customers who use less than baseline quantities. As the Commission stated in connection with PG&E's proposal, the "key legal question":

... is whether the imposition of a fixed customer charge is included within the Sec. 739.1(b)(2) and 739.9(a) annual rate limitations applicable to electric usage up to 130 percent of baseline. Based on our analysis of the statutory provisions as discussed below, we do interpret Sec. 739.1(b)(2) and 739.9(a) as including fixed customer charges within the limitations on allowable percentage increases in "rates for

[2] See D.12-03-056, Order Denying Rehearing of Decision 11-05-047.

> *usage." Thus, we are prohibited by law from approving PG&E's customer charge to the extent the total bill impacts exceed these statutory limitations on baseline rate increases. (D.11-05-047, p. 24.)*

The Commission went on to explain:

> *In this context, although a fixed customer charge is not applied on a per-unit volumetric usage basis for billing purposes, the Commission has still recognized fixed customer charges in calculating customer-related bill impacts for usage within baseline quantities. Accordingly, even though the customer charge is not a volume-based billing determinant, the customer charge is still relevant in calculating the "rate for usage" in the context of identifying impacts on customers usage in Tier 1 (i.e., baseline quantities) or Tier 2 (up to 130 percent of baseline usage). Irrespective of whether rate design is configured to recover customer-related costs as a fixed amount or through a per-unit consumption rate, the customer impact is the same. The customer charge is thus included within the "rates… for electricity usage up to 130 percent of baseline usage…" as referenced in Sec. 739.1(b)(2) and 739.9 9(a).(D.11-05-047, pp.29-30)*

In its Order denying rehearing of D.11-05-047, the Commission discusses further the rate protections from SB 695, saying:

> *The interpretation promoted by the joint applicants for rehearing would effectively deprive Tier 1 and 2 customers of their primary protection in section 739.9(a). Following the rate freeze, which shielded residential customers consuming less than 130 percent of baseline from rate increases for a number of years, the Legislature, through SB 695, established a means for phased-in rate increases, so that the affected customers were provided some protection, through statutorily identified limitations, from suffering rate shock as the result of sudden rate increases. Under the outcome proposed by the joint applicants for rehearing significantly different charges could be assessed to PG&E's CARE and non-CARE customers, as well as significant increases to the total rates charged to CARE customers using up to 130 percent of baseline quantities. The outcome demanded by the joint applicants for rehearing defies the logic of the legislation at issue and does not comport with the legislative history. The*

> *arguments of the joint applicant for rehearing that PG&E's proposed increase would not undermine the legislative intent and is not prohibited by the legislation at issue are without merit. Joint applicants for rehearing have failed to establish the challenged decision erred. (D.12-03-056, p.12)*

The same legal standards that apply to PG&E's proposed residential customer charge also apply to SDG&E's.

The imposition of a fixed customer charge should be included within the Sec 739.1(b) (2) and 739.9(a) annual rate limitations applicable to electric usage up to 130 percent of baseline usage. Section 739.9(a) provides:

> *The commission may, subject to the limitation in Subdivision (b), increase the rates charged residential customers for electricity usage up to 130 percent of the baseline quantities, as defined in Section 739, by the annual percentage change in the Consumer Price Index from the prior year plus 1 percent, but not less than 3 percent and not more than 5 percent per year. For purposes of this subdivision, the annual percentage change in the Consumer Price Index shall be calculated using the same formula that was used to determine the annual Social Security Cost of Living Adjustment on January 1, 2008. This subdivision shall become inoperative on January 1, 2019, unless a later enacted statute deletes or extends the date.*

Section 739.1(b)(2**)** provides:

> *The commission may, subject to the limitation in paragraph (4), increase the rates in effect for CARE program participants for electricity usage up to 130 of baseline quantities by the annual percentage increase in benefits under the CalWORKS program as authorized by the Legislature for the fiscal year in which the rate increase would take effect, but not to exceed 3 percent per year.*

SDG&E's proposal, like that of PG&E, would effectively deprive residential customers of these rate protections. SDG&E's proposal, like PG&E's, should be rejected.

SDG&E proposes to remedy these legal problems by reducing its tier 1 residential volumetric rates by approximately 1 cent per kWh to offset the bill impacts of a $3 customer charge. The additional proposal to reduce the tier 1 volumetric rate is, however, insufficient to maintain the rate protections contained in PU Code sections 739.9(a) and 739.1(b)(2). While it might leave customers who consume at levels equal to or above their baseline allowances indifferent, customers with usage below baseline would receive bill increases that are greater than what is allowed by PU Code section 739.9(a).

The rate protections from Sections 739.9(a) and 739.1(b) (2) apply to *all* residential customers with usage up to 130% of baseline usage, including customers who use less than the baseline allowance. SDG&E's proposals may comply with the law for residential customers with usage between baseline and 130% of baseline usage, but they do not comply for all residential customers with usage below baseline. SDG&E's proposal for a residential customer charge thus would deny the rate protections the Legislature mandated for lower usage residential customers.

The Section 739.1(a) and 739.9(a) rate protections include fixed customer charges within the allowable percentage increases for usage up to 130% of baseline usage for all residential customers. If SDG&E's residential rate design proposals are adopted, residential non-CARE customers with usage below the baseline usage level would receive bill increases as high as 21.7%. CARE customers with usage below the baseline usage level would receive bill increases as high as 24.5%. Non-CARE residential customer consuming electricity at 25% of baseline quantities would receive bill increases of 20.3% to 21.7%[3] in the coastal climate zone and 17.5% to 18.5%[4] in the inland climate zone[5]. CARE customers consuming electricity at 25% of baseline quantities, would receive bill

[3] This range of bills is based on summer and winter billing periods and baseline allowances.

[4] The information is contained in SDG&E's response to DRA Data request DRA-DR-09, question 9.

[5] The coastal and inland climate zones account for approximately 99% of SDG&E customers.

increases of 22.9% to 24.5% in the coastal climate zone and from 19.8% to 20.9%[6] in the inland climate zone.

These increases clearly exceed the allowable increases of 3% to 5% per year for non-CARE residential customers and the current cap of zero for CARE customers[7]. Furthermore, these bill impacts do not take into account the annual request to increase tier 1 and tier 2 rates that SDG&E and the other electric Investor Owned Utilities ("IOUs") make each year since SB695 was passed. For example, the bill impacts cited above do not take into account the 5% increases to Tier 1 and Tier 2 rates that SDG&E implemented on January 1, 2012[8], or additional requests for Tier 1 and Tier 2 rate increases that it will likely make for January 1, 2013.

In D.11-05-047, the Commission examined the Legislative intent behind SB 695 stating:

> *In reference to the legislative history of SB 695, the Legislature has stated that "by restricting rate increases to an annual narrow range and controlling the increase within relatively small parameters, SB 695 is intended to minimize spikes in electricity rates and provide relative stability and predictability."[9] Consistent with this express intent, the limitations in "rate" increases must be interpreted consistent with providing "relative stability and predictability" in customers' rates. Ignoring the effects of a fixed customer charge in assessing permissible statutory rate increases would conflict with this stated intent of SB 695. Otherwise, merely imposing limits on volumetric tiers would have little meaning if a fixed customer charge could be imposed without regard to such limits, and thereby undermine the intended overall rate stability. No customer using only baseline*

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[6] This information is contained in SDG&E's response to DRA Data request DRA-DR-09, question 11.

[7] CARE rate increases for usage up to 130% of baseline quantities, is tied to the CalWorks program escalator. Because of state budget difficulties in the last few years, there have been no increases to the CalWorks escalator.

[8] The 5% Tier 1 and Tier 2 rate increases were implemented via Advice Letter 2303-E.

[9] Assem. Com. On Appropriations Analysis of SB 695 (2009-10 Reg. Sess.) August 19, 2009, at 2-4 see also Sen. Floor Analysis of SB 695, Sept. 2, 2009.

> *quantities could avoid the customer charge. Thus, it is logical to infer that the Legislature intended that all rate elements relevant to baseline usage be included for purposes of "restricting rate increases." Thus, by examining the legislative intent, we resolve the ambiguity in favor of interpreting customer charges as being included within the intended use of the term "rates" in Sec. 739.1(b)(2) and 739.9(a). (D.11-05-047, pp25-26)"*

As D.11-05-047 notes, while Sec 739(a) does not explicitly mention "customer charges," it does refer to "rates ... for electricity usage up to 130 percent of baseline quantities," and Commission decisions have repeatedly recognized that baseline rates include any fixed customer charges. D.11-05-047 includes a partial list and description of some of those decisions. (D.11-05-047, pp. 28-29.)

For example, in D.91107, issued in 1979, the Commission stated, [a]s the customer charge is an integral component of the lifeline charge, an increase in the customer charge is a disguised form of an increase in the lifeline rates." (D.91107, mimeo, pp. 143-144, 2 CPUC 2d 596.) In D. 92497, issued in 1980, the Commission stated:, "[w]e fail to see how doubling the customer charge produces an inexpensive lifeline rate since the customer charge is part of the lifeline."(D.92497, p. 824, 4 CPUC 2d 725, 824).

In D.00-04-060 for a SoCalGas Biennial Cost Allocation Proceeding, the Commission provided the following summary of this issue:

> *Section 739(c) (Public Utilities Code) requires the Commission to establish "baseline rates" which apply to the lowest block of an increasing block rate structure. The statute is premised on the principle that "electricity and gas are necessities, for which a low affordable rate is desirable." (739 (c)(2)). Section 739.7 similarly requires an "appropriate inverted rate structure". These code sections have been consistently interpreted to include the customer charge in determining whether the rate structure is, in fact, inverted. Under this "composite tier differential" approach, customer charges are considered part of the Tier I, or baseline, rate for the purpose of calculating tier differentials. (D.87-12-039, 26 CPUC2d 213,270; D.89-01-055; D.97-04-082, p.118)" (D.00-04-060, p.107)*

> *We reject SoCalGas' proposal. As we said in the last SoCalGas BCAP, "Therefore we should retain the existing tier differential calculated on a composite basis.* ***The composite tier differential is more meaningful than the simple differential because it gives the price for access and purchase of a quantity of gas that covers basic needs****. (D.00-04-060, p.107, emphasis added.)*

Other Commission decisions that discuss this issue include D.87-12-039, the implementation decision of the restructuring of the gas industry. In that decision, the Commission stated:

> *...the issues raised during this proceeding concern the imposition of new customer charges, the increase of present customer charges, and the question of whether to include customer charges in the calculation of baseline rates.* The issue of whether customer charges must be included in the calculation of the baseline rate is so well settled in favor of inclusion that it requires no further discussion. Our current policy will continue. (D.87-12-039, 26 CPUC 2d 270)

Thus, in previous cases, and most recently in D.11-05-047, the Commission has thoroughly reviewed the law, the Legislative intent and previous decisions applicable to residential customer charges. Just as the Commission rejected PG&E's proposed residential customer charge in D.11-05-047, so too should it reject SDG&E's in this case.

2. SDG&E's proposal for a residential charge is contrary to public policy

DRA also opposes SDG&E's residential customer charge on policy grounds. SDG&E's proposal would result in excessive bill impacts, especially for low-usage low-income customers. Fixed charges also limit the ability of customers to control the size of their bills. A customer charge also is unnecessary if the existing minimum charge is maintained.

In D. 11-05-047, the Commission examined PG&E's proposed residential customer charge in light of public policy stating:

> *We also consider, however, the potential adverse bill impacts of a customer charge, particularly on low-income households. Aside from any legal restrictions the fact remains that a fixed customer charge would be an unavoidable component of the bill of every residential customer, including those whose usage remained within baseline. Because a fixed customer charge cannot be avoided by a customer's reducing usage or being more energy efficient, the customer charge offers no conservation price signal. (D.11-05-047, p.33)*

The same reasoning applies here. SDG&E's residential rate design proposals would result in bill increases for many residential customers, especially low-income customers. Approximately 36.7% of non-CARE residential customers[10] and approximately 80%[11] of CARE customers would receive bill increases if SDG&E's proposals are adopted. SDG&E's proposals include its revenue allocation proposal for a 1.36% decrease for the residential class. But they do not take into account any revenue requirements increases such as from SDG&E's GRC Phase I requests.

For non-CARE residential customers, 8.2% would experience bill increases of 6% or greater; 4.7% would experience bill increases of 10% or greater; 2.7% would experience bill increases of 15% or greater; 1.7% would experience bill increases of 20% or greater; and 6,899 customers or 0.7% would experience bill increases of 30% or greater. For CARE customers 13.7% would experience bill increases of 6% or greater; 6.5% would experience bill increases of 10% or greater; 3% would experience bill increases of 15% or greater; 1.5% would experience bill increases of 20% or greater; and 1,078 customers or 0.4% would experience bill increases of 30% or greater[12]. Clearly, the bill impacts are more for SDG&E's CARE customers than for non-CARE customers.

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[10] This information is contained in SDG&E's response to DRA-DRA-09, q.1.

[11] This information is contained in SDG&E's response to DRA-DRA-09, q.2.

[12] The average bill increase is actually 41% for the group of CARE customers with bill increases of 30% or greater.

IOUs may like fixed charges as they provide stable revenues for IOUs. However, fixed charges give customers less control over the level of their bills. No change in customer behavior or consumption would reduce or eliminate the fixed customer charge. DRA believes that customers should have as many ways as possible of controlling the level of their bills—especially during difficult times like the recent economic recession and the drawn out recovery.

SDG&E currently has a minimum charge of 17 cents per day or roughly $5.10 per month, which helps collect for IOU facilities that are in place to serve customers. For customers with no or very low usage, a minimum charge functions like a customer charge and collects fixed revenue. Customers who use more energy (and whose bills exceed $5.10 per month) do not pay the minimum charge and pay for customer access through their volumetric rates. A minimum charge ensures that a customer who uses little or no electricity will contribute to the cost of customer access facilities.

B. Combining Tier 3 and Tier 4 rates to create a new Tier 3 rate

SDG&E went from a 5-tier increasing block residential rate design to a 4 tier rate design in 2008, when D.08-02-034 adopted a settlement of residential rate design issues. PG&E went to a 4-tier residential rate design in June 2010 as part of a settlement, and SCE is proposing to move to a 4-tier residential rate design in its current GRC Phase II proceeding.

DRA opposes SDG&E's proposal to combine residential tier 3 and tier 4 rates because:

1) The Commission recently issued a decision maintaining PG&E's 4-tier residential rate design;
2) This is a bad time to reduce the number of tiers because the utilities are all building into their customer on-line interfaces the capability enabled by AMI to alert customers when they cross from one tier to the next.
3) Rates for customers in the current tier 3 usage range would increase, creating bill impacts;
4) There would be less incentive to conserve after usage exceeds 200% of baseline usage;

5) The proposal would harm medical baseline customers who currently do not pay rates higher than tier 3 rates;

6) Combining tiers 3 and 4 would likely in the future lead to even higher differentials between tier 2 to tier 3 rates, where there is already large rate differentials; and

7) Residential rate increases in the future would primarily be recovered in tier 3 rates, putting additional pressure on CARE tier 3 rates.

DRA recommends that the Commission also maintain 4 tiers of residential rates for SDG&E while the Commission considers other changes to residential rate design.

As indicated above, the Commission recently examined a similar proposal by PG&E, in its GRC Phase II proceeding, to combine residential tier 3 and tier 4 rates, and rejected PG&E's proposal. At the same time, the Commission established a 4 cent per kWh differential between tier 3 and tier 4 rates. This was the first time that this issue had been litigated since the implementation of the 5 tier residential rate design in 2001.

In D.11-05-047, the Commission rejected PG&E's proposal on the following basis:

> *We conclude, however, that a complete consolidation of Tiers 3 and 4 goes too far. Accordingly, we reduce the Tier 4 rate somewhat, but require that a Tier 4 differential of at least four cents per kWh be maintained between Tiers 3 and 4. (p.48)*
>
> *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. (p.48)*

The second reason for not collapsing tiers 3 and 4 is that new AMI meter capabilities should be available which will provide customers with better and timelier information regarding their monthly consumption. Customers can now be alerted when they are about to move from tier 1 to tier 2, and when they are about to move to a higher rate tier. They also can be informed what rate they will be paying, and when their bill reaches specified levels. Leaving the current rate design in place would allow for observing the effectiveness of the combination of this rate design and AMI Meter and customer notification capabilities in promoting conservation.

The third reason for not combining tiers 3 and 4 is that doing so would result in increases to the residential tier 3 rate. And this rate will increase still further if SDG&E receives a GRC Phase I revenue requirements increase. DRA's proposed rates provide decreases to both tier 3 and tier 4 rates.

A fourth reason why DRA opposes SDG&E's proposal is that it would provide incentives to not consume above 130% of baseline usage. And it would provide even less incentive to not consume electricity once a customer was consuming at 200% of the baseline allowance (twice the baseline allowance). While there is a small increase between the tier 1 and the tier 2 rates, (2.2 cents per kWh), there is a large increase to the tier 3 rate (roughly a 9 cents per kWh increase in the summer). In the future, a 3-rate tier rate structure would likely result in even greater differentials between the tier 2 and tier 3 rates. If a tier 4 rate is maintained, some of future revenue requirements increases could be spread to the tier 4 rate.

A fifth reason for opposing SDG&E's proposal is that it would harm medical baseline customers who currently do not pay Tier 4 rates. Medical Baseline customers pay the Tier 3 rate for all usage above 130% of baseline usage. Combining the Tier 3 and 4 rates would result in higher Tier 3 rates that would result in bill increases for Medical Baseline customers who consume at Tier 3 levels.

Finally, this proposal would put more pressure on CARE tier 3 rates to increase in the future, as CARE tier 3 rates are linked to the level of non-CARE tier 3 rates. Combining the Tier 3 and 4 rates would result in higher tier 3 rates than if there were both tier 3 and tier 4 rates to absorb residential revenue requirements increases. Hence, CARE tier 3 rates would be impacted less in the future if SDG&E's proposal to combine tiers 3 and 4 is rejected.

C. CARE Tier 3 Rates

SDG&E proposes to remove the cap on CARE residential tier 3 rates on a going-forward basis. Currently SDG&E's CARE tier 3 rate is 17.5 cents per kWh in the summer and 16.4 cents per kWh in the winter. SDG&E proposes to increase these rates to 17.7 cents per kWh in the summer and 15cents per kWh in the winter. This proposal is on top of SDG&E's proposal for a $3 per month CARE customer charge. SDG&E's proposed rates are based on updating marginal costs and removing the cap on CARE tier 3 rates, and do not include increases in revenue requirements. Thus, removing the caps on the CARE tier 3 rates would result in even greater increases to those rates than SDG&E has shown when revenue requirements increases from SDG&E's GRC Phase I proceeding or other proceedings are implemented.

DRA's revenue allocation and rate design proposals would result in a CARE tier 3 rate of 14.4 cents per kWh in the summer and 12 cents[13] per kWh in the winter. Thus, if DRA's proposals are adopted, there would not be a need for a cap on CARE tier 3 rates immediately. However, it would be prudent for the Commission to institute a cap on the level of CARE tier 3 rates between rate cases to provide some insurance for low income customers.

Though SDG&E recommends removing the cap on CARE tier 3 rates, it has not provided forecasts of potential increases to CARE tier 3 rates that could occur before its next GRC. If DRA's revenue allocation and rate design proposals are adopted, CARE tier 3 rate increases would not occur in this proceeding. But CARE tier 3 rate increases could occur as a result of revenue requirements increases in other proceedings or because of balancing account amortizations. Rates are not examined as thoroughly in these other proceedings, thus, it makes

[13] These proposed CARE tier 3 rates would likely increase if a cap to the revenue allocation is implemented.

better sense to set a policy on CARE rates in this rate design proceeding. The potential for CARE rate increases over the next three years should be considered when setting CARE rates policy and before the cap on CARE tier 3 rates is removed.

DRA recommends that a cap on CARE tier 3 rates at a maximum of 18 cents per kWh be adopted in this proceeding, and that this cap remain until SDG&E's next GRC. Setting a cap on CARE tier 3 rates is preferable to allowing a series of "flow through" or non-litigated rate increases for CARE customers for the three years between rate cases. Unlimited CARE tier 3 rate increases could result in CARE tier 3 rates that violate the spirit of Public Utilities Code Section 382 (b) which states:

> *In order to meet legitimate needs of electric and gas customers who are unable to pay their electric and gas bills and who satisfy eligibility criteria for assistance, recognizing that electricity is a basic necessity, and that all residents of the state should be able to afford essential electricity and gas supplies,* ***the commission shall ensure that low-income ratepayers are not jeopardized or overburdened by monthly energy expenditures****. Energy expenditure may be reduced through the establishment of different rates for low-income ratepayers, different levels of rate assistance, and energy efficiency programs. (Emphasis added)*

A cap on CARE tier 3 rates is a better policy than allowing unlimited non-litigated increases to CARE rates.

D. Rate Presentation

SDG&E proposes to improve its residential rate information by presenting total residential rates in one location in its tariffs. It states:

> *San Diego Gas & Electric Company (SDG&E) proposes changes to the format of residential UDC rate schedule tariffs to identify the total rates billed customers by SDG&E rather than only the UDC rates. Currently, residential customers taking bundled service need to review three separate tariffs (UDC, EECC, and DWR-BC) to identify the total rates paid to SDG&E. Although it displays total rates for residential*

customers on its web page (www.sdge.com), SDG&E believes it would provide greater clarity to its customers if the total rate were also presented on the UDC tariffs. For this reason, SDG&E proposes format changes to residential UDC tariffs to identify total rates by tier and /or TOU period. (SDG&E Testimony, Chapter 4, pp.WGS-1 to WGS-2)

DRA supports SDG&E's proposal to show total residential rates in one location in SDG&E's tariffs. This change will help customers better understand what they are paying for their electric usage, and hopefully will reduce customer confusion and inquiries to SDG&E.

SDG&E also proposes to separate TRAC and PPP charges on residential customer bills. DRA notes that this was the practice in the past but was changed in an attempt to reduce customer enquiries. DRA recommends a full discussion of this issue and how to reduce customer enquiries by all parties representing residential customers in residential rate design settlement talks.

IV. CONCLUSION

DRA recommends that the Commission deny SDG&E's proposal to institute a residential customer charge (or BSF) on both legal and policy grounds. The Commission examined and denied a similar proposal in PG&E's GRC Phase II, in D.11-05-047, and the same legal standards apply to SDG&E's proposal.

DRA also recommends that the Commission maintain SDG&E's current 4 tier residential rate design for the present. In D.11-05-047, the Commission maintained PG&E's 4 tier residential rate design, and SCE is proposing to move to 4 residential rate tiers in its GRC Phase II proceeding. This is a good point to pause and reflect while the Commission considers other changes to residential rate design.

DRA recommends adopting a cap of a maximum of 18 cents per kWh on CARE tier 3 rates until SDG&E's next GRC Phase II proceeding. This would prevent unlimited non-litigated pass-throughs of rate increases for CARE customers.

Finally, DRA strongly supports SDG&E improving its residential rates presentation to make it easier for residential customers to understand SDG&E's residential rates.

CHAPTER 6

SMALL COMMERCIAL RATE DESIGN

ROBERT LEVIN

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CHAPTER 6

SMALL COMMERCIAL RATE DESIGN

ROBERT LEVIN

I. INTRODUCTION

This chapter presents DRA's recommended small commercial rate designs for 2012 through 2014. Over 90% of SDG&E's roughly 124,000 small commercial customers are served under Schedule A, on which the customers pay a fixed customer charge and a flat energy rate. There are no demand charges for this schedule. Roughly 6% of small commercial customers are served under A-TC Traffic Control Service, and about 1% under the now-closed time-of-use schedule A-TOU.

SDG&E's Schedule A customers now pay a monthly customer charge of $9.56 and a flat seasonal volumetric charge. SDG&E is not proposing any change in this basic rate structure. However, SDG&E is proposing to double the customer charge for this group, to $19.11 per month by 2014.[1] By way of justification, SDG&E's testimony states: "SDG&E identifies the distribution customer costs of providing service to small commercial customers to be $62.41 per month."[2]

As discussed below and in Chapter 3 of DRA's testimony, SDG&E's estimate of its "distribution customer costs of providing service to small commercial customers" is far out of line with the corresponding costs of SCE and PG&E. SDG&E's stated cost of $62.41 per customer-month is at least 216% of SCE's cost estimate based on a similar methodology.[3] DRA proposes a

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[1] Ex. SDG&E-102, p.CF-12. An intermediate increase to $14.33 is proposed for 2013.

[2] Id.

[3] SCE's proposed rental method GS-1 marginal customer cost in its 2012 GRC phase 2 was $28.90 per month based on 3-phase service. For single phase service, SCE's proposed rental method marginal customer cost was $13.63 per customer-month. DRA recommended a small commercial marginal customer cost of $28.71 per customer month for PG&E in its 2011 GRC Phase 2, A.10-03-014.

marginal customer cost of $24.42 per customer-month[4] for the small commercial class.

However, even DRA's lower marginal customer cost masks the fact that nearly 10% of customers served under SDG&E's small commercial rate schedules do not fit the Commission's definition of a "small" commercial customer. The Commission has defined "small commercial" as having a maximum demand of no more than 20 kW. SDG&E appears to concur with this definition.[5] As discussed in Chapter 3, if the class of customers served under SDG&E's small commercial rate schedules were restricted to true small commercial customers, the resulting marginal customer cost for that class would be $17.65 per month.[6]

Based on SDG&E's proposed billing determinants and marginal demand-related distribution costs, together with DRA's proposed marginal customer cost of $24.42, DRA proposes a 3.92% average rate increase for the small commercial class (cf. Chapter 4). This is a reduction from the 5.79% increase proposed by SDG&E. DRA performed a sensitivity run of SDG&E's rate model using the lower $17.65 MCC value specific to true small customers. Under this DRA scenario, the small commercial class would have received only a 1.04% rate increase.

DRA concludes that the presence of medium commercial customers[7] on rate schedules intended for small commercial customers tends to make those rates higher than they should be. To remedy this situation in the short run, DRA proposes to freeze the current customer charge for the smallest customers (under 12 kW) while imposing substantial increases in the customer charges paid by the largest customers served under Schedule A and related small commercial rate

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[4] This equals the DRA recommended marginal customer cost value for the small commercial customer class in Table 3-2 ($292.99 per customer-year), divided by 12.

[5] Ex. SDG&E-102, p.CF-11

[6] This is very close to the $13.63 per customer-month SCE proposed in its 2012 GRC phase 2 for GS-1 single phase service.

[7] With maximum demand greater than 20 kW.

schedules. In the longer run, DRA proposes that customers larger than 25 kW[8] be made ineligible for Schedule A and moved to a rate schedule appropriate for medium commercial customers.

DRA is not opposed to customer charges for nonresidential customers, but is mindful that such charges can be detrimental to the smaller customers within a class, especially when large increases are contemplated, as with SDG&E's proposal. Accordingly, DRA proposes to increase customer charges only for the larger users. About 80% of the customers on Schedule A and related schedules have maximum demands of between 0 and 12 kW. Yet about 8% of the customers on Schedule A and related schedules have maximum annual demands greater than 20 kW, and over 1,000 of these customers exceed 50 kW.[9]

SDG&E's proposed rates would charge the same customer charge to a 5 kW customer and a 50 kW customer served under Schedule A. It could be argued that the cost of providing a meter, reading that meter, and sending a bill are identical for the two customers. But there are other costs included in marginal customer costs, such as the transformer and service extension, that clearly increase with customer size.

To address cost differences within the set of customers served under Schedule A, DRA proposes a four-level customer charge, in which the roughly 80% of customers under 12 kW would pay the existing customer charge of $9.56 per month. Those with maximum demands between 12 and 25 kW would pay $11 per month, and the larger customers (who are not "small" commercial customers as defined by the Commission), would pay monthly charges of either

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[8] In its marginal customer cost workpapers, SDG&E grouped its customers into "bins" by customer size, measured by maximum demand in kW. One of these bins, 13 to 25 kW, straddles the 20 kW upper limit for small commercial customers. Thus, for convenience, DRA uses 25 kW as a working upper size limit for small commercial customers, for the purposes of this testimony. Doing so would also protect some customers near the Commission's 20 kW upper boundary from rate shock caused by potential reclassification to the medium commercial group.

[9] Source: A table in SDG&E's workpapers which provided a breakdown of SDG&E's customer population by rate schedule and maximum annual demand, based on 2009 billing data.

$19.11 or $87.34 per month depending on their size bracket.[10] These charges are calibrated to provide roughly the same total revenue as a uniform $11.14 monthly customer charge, which is about 17% more revenue than that produced by the current $9.56 customer charge.

Under DRA's four-level customer charge proposal, the smallest customers (under 12 kW) would experience rate increases of about 3.12%, compared with the average customer's increase of 3.92% under DRA's proposal and 5.79% under SDG&E's proposal. To improve SDG&E's ability to provide accurate cost-based rates, SDG&E should move the nearly 9,000 larger customers (above 25 kW) now served under small commercial rates to one of the rate schedules intended for medium commercial customers.

Finally, DRA notes that fewer than 1% of SDG&E's small commercial customers are on TOU rates, and that the one available TOU rate schedule designed for small commercial customers, Schedule A-TOU, is now closed. TOU rates for small commercial customers were addressed in SDG&E's Dynamic Pricing Application ("DPA"), A.10-07-009. In its DPA, SDG&E proposed a small commercial TOU rate with a demand charge. A settlement agreement in the DPA proceeding was filed on June 20, 2011. In this settlement, the parties agreed that, for small commercial customers "SDG&E shall implement optional TimeOfDay (TOD) (also referred to as Time Of Use or TOU) pricing with no demand charge effective March 1, 2013"; and "The time periods and differential for TOD rates will be addressed in SDG&E's 2012 GRC Phase II proceeding."

As of the filing of this DRA testimony, the all-party Settlement in A.10-07-009 is still pending before the Commission. While not discussed in its testimony, SDG&E has included a small commercial TOU rate "AS-TOD" in its proposed rates. DRA notes, with approval, that the proposed AS-TOD rate lacks a demand charge component, and DRA does not object to this rate as an optional

[10] For comparison purposes, a medium commercial customer (e.g., Schedule AL-TOU), under SDG&E's proposal, would pay a customer charge of $87.34 per month.

rate for small customers[11]. However, DRA proposes that SDG&E develop a "milder" less strongly time differentiated rate option for customers who would prefer a more cautious transition to TOU rates.

II. SUMMARY OF RECOMMENDATIONS

DRA recommends the following:

1. Small commercial customers should remain, as a default, under a two-part rate consisting of a fixed monthly customer charge and a volumetric energy rate.
2. SDG&E's proposal to double the current small commercial customer charge to $19.11 per month should be rejected.
3. SDG&E should institute a graduated four-level customer charge as set forth in Table 6-1.
4. SDG&E's Schedule A volumetric rate should be set at $0.18809 per kWh (summer), and $0.14863 per kWh (winter)[12].

Table 6-1

DRA's Recommended Small Commercial Customer Charges

Customer Group	Max. Annual Demand (kW)	Percent of Cust. On Sm. Comm. Rates	Recommended Customer Charge ($/mo.)	% Chg. From Current Cust. Chg.
A	0 to 12	80%	$9.56	0%
B	13 to 25	12%	$11.00	15%
C	26 to 50	6%	$19.11	100%
D	over 50	1%	$87.34[13]	814%

[11] DRA does object, however, to the size of the customer charge, and recommends the same four-level customer charge structure for all small commercial rate schedules.

[12] For the large majority of customers taking service at secondary distribution voltage.

[13] This is identical to SDG&E's customer charge proposal for the medium commercial Schedule AL-TOU.

5. Prior to its next GRC, SDG&E should move the larger customers (above 25 kW) now served under small commercial rates to one of the rate schedules intended for medium commercial customers.
6. In its DPA proceeding, SDG&E should design and propose a new optional TOU rate schedule for small commercial customers[14] that is a mildly time-differentiated rate similar to PG&E's A1-TOU rate.
7. In addition, SDG&E should design and propose at least one optional small commercial EV-TOU rate schedule with a super-off-peak period for small commercial electric vehicle owners.
8. Rate schedules intended for small commercial customers should not include demand charges.

III. DISCUSSION

A. Small Commercial Marginal Customer Cost

As noted above and discussed in Chapter 3, DRA has identified serious problems with SDG&E's marginal distribution customer costs. These were greatly overestimated for smaller customers in SDG&E's testimony. DRA's recommended marginal customer costs result in a reduced allocation of the revenue responsibility to the small commercial customer class, and a reduction in Schedule A rates relative to SDG&E's proposal as discussed above.

Even with DRA's proposed MCC corrections, DRA believes that SDG&E's small commercial rates are biased and too high due to the presence of significant numbers of larger customers taking service on Schedule A and related rate schedules. DRA's four-level customer charge proposal is an attempt to compensate for that bias by holding down rate increases to the true small commercial customers (under 20 kW).

[14] A.10-07-009.

B. DRA's Small Commercial Customer Charge Proposal

DRA's proposed four-level customer charges are designed to yield about the same revenue as a hypothetical flat $11.14 per month fixed charge, which is about 17% more than the current $9.56 per month customer charge. However, DRA's proposal reflects differences in fixed cost causation within the group of customers currently served under small commercial rates.

The purpose of customer charges (e.g., SDG&E's Basic Service Fee) is to recover a portion of SDG&E's class-specific marginal distribution customer cost. DRA has determined the class average small commercial marginal distribution customer cost to be $24.42 per customer-month. This cost includes capital and O&M costs associated with final line transformers ("FLTs"), service connections, and meters, as well as costs for services such as meter reading, billing, and customer inquiry. While some costs such as billing do not vary with customer size, other costs such as those associated with FLTs, vary strongly with the customer's maximum demand. Typically the FLT cost is the largest single component of a customer's marginal distribution customer cost. For the smallest customers (e.g., under 2 kW), several customers often share a single FLT. Such customers represent more than one-third of small commercial customers. Larger members of the small commercial class (e.g., 12 kW and up) typically are served from a dedicated FLT.

The size (capacity) of the FLT itself can depend on the customer's maximum demand. The same is true to some extent for the service drop, especially where larger customers are situated on larger lots with longer service extensions.

For these reasons, a 50 kW customer should pay a higher customer charge than a 5 kW customer. This would be the outcome of SDG&E's proposed rates if the 50 kW customer were correctly classified as a medium commercial customer and served on a rate schedule such as AL-TOU, which is intended for medium commercial customers. In that case, the 50 kW customer would pay $87.34 per month under SDG&E's rate proposals, while the 5 kW customer would pay $19.11 per month (beginning 2014). However this would not be the outcome for the more than 1,000 50 kW customers currently served under Schedule A and related schedules. Under SDG&E's rate proposals, these customers would be charged $19.11 per month, the same amount as a customer with a 5 kW maximum demand, or even a customer with a 1 kW maximum demand.

As discussed above, the marginal customer cost for the customers served under Schedule A and related schedules is significantly impacted by the presence of customers with maximum demands above 20 kW. In recognition of this fact, DRA proposes to freeze the current customer charge for the smallest customers, that is, those who impose a demand of 12 kW or less (Customer Charge Group A in Table 6-1). For Group B (13–25 kW), DRA proposes an $11 customer charge for this group.

Customers in Groups C and D are not true small commercial customers as they have maximum demand exceeding 25 kW. As previously stated, DRA proposes that Group D customers pay the same customer charge as SDG&E proposes for AL-TOU, that is, $87.34 per month. DRA proposes an intermediate value of $19.11 per month for Group C customers.[15]

In summary, the multilevel customer charges that DRA proposes better reflect cost causation than the single "one-size-fits-all" customer charge proposed by SDG&E, and collect somewhat more revenue than SDG&E's current $9.56 small commercial customer charge. About 80% of the customers on SDG&E's small commercial rate schedules would see no change in their monthly customer charges. The remaining true small commercial customers would see about a 15% increase to a level ($11 per month), which is far below the $19.11 proposed by SDG&E.

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[15] This is identical to SDG&E's proposal for 2014 and is double the current customer charge.

C. Medium Commercial Customers should not be Served Under Rates Intended For Small Commercial Customers

Currently, customers on Schedule A, and related rate schedules intended for small commercial customers, range up to 75 kW and beyond.[16] Having such a broad mix of customers in a single rate class interferes with SDG&E's (and other parties') ability to formulate accurate cost-based rates specifically tailored to true small commercial customers. Further, as discussed above, the presence of larger customers tend to increase the marginal customer cost, and the rates, for the small commercial customer class as a whole.

DRA's proposed four-level customer charge, if adopted, would only partially compensate for this distortion caused by including larger customers. Thus, to further protect true small customers from unjustified rate increases, and improve SDG&E's ability to provide accurate cost-based rates, SDG&E should be required to move the nearly 9,000 larger customers (above 25 kW) now served under small commercial rates to one of the rate schedules intended for medium commercial customers. DRA recommends that such a move be completed before SDG&E's next GRC. A similar proposal was adopted for PG&E in its most recent GRC, Phase 2 (A.10-03-014).

D. SMALL Commercial Customers Deserve the Opportunity to be on Time-of-Use Rates

As noted above, less than 1% of SDG&E's small commercial customers are now on TOU rates, and the one available TOU rate schedule designed for small commercial customers (Schedule A-TOU) is now closed. TOU rates surely could benefit some small commercial customers, and TOU rates offer significant benefits to utilities and to the environment.[17]

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[16] Per SDG&E's workpapers, nearly 200 customers with demand greater than 75 kW were served on small commercial rate schedules in 2009.

[17] For a discussion of the economic and environmental benefits of TOU rates, see Friedman, Lee S., "The Importance of Marginal Cost Electricity Pricing to the Success of Greenhouse Gas Reduction Programs" Energy Policy, 39, No. 11, November 2011, pp. 7347-7360, and DRA's

(continued on next page)

DRA regards SDG&E's proposed AS-TOD rate, which does not have a demand charge component, as a step forward. Except for the customer charge, DRA has no objection to offering this rate on an optional basis for customers with maximum demands not exceeding 20 kW. However, the proposed AS-TOD rate is highly time-differentiated and may present an overly abrupt a transition to customers on the flat rate Schedule A who wish to transition directly to AS-TOD. Therefore, DRA recommends that SDG&E design and propose a new optional TOU rate schedule for small commercial customers that would be mildly time-differentiated in a way similar to PG&E's A1-TOU rate. DRA recommends that both optional TOU rate schedules have the four-level customer charge proposed above in Table 6-1.

In addition, SDG&E should ensure that small commercial customers who own electric vehicles have access to at least one TOU rate schedule with a super-off-peak period tailored to minimize the cost of overnight vehicle charging. SDG&E has proposed a similar rate schedule, which is now pending, for electric vehicles owned by residential customers (Schedule EPEV-Y).

DRA recommends that the additional optional small commercial TOU rates discussed above be proposed in supplemental filings or advice letters either in the instant GRC Phase 2 proceeding or in the DPA proceeding, with a target effective date of March 1, 2013 or sooner.

IV. CONCLUSION

The Commission should adopt DRA's rate design recommendations for SDG&E's small commercial rate schedules because they would protect true small customers[18] from rate shock. They also would increase the equity of rates among

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May 2011 white paper: Time-Variant Pricing for California's Small Electric Consumers, http://www.dra.ca.gov/DRA/energy/hot/110524_tou.htm

[18] As defined by the Commission in D.08-07-045.

customers served on SDG&E’s small commercial rate schedules and enhance the accuracy of SDG&E’s rates in reflecting cost causation.

CHAPTER 7

PREPAY PROGRAM

LEE-WHEI TAN

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CHAPTER 7

PREPAY PROGRAM

LEE-WHEI TAN

I. INTRODUCTION

This chapter addresses DRA's analysis and proposals for SDG&E's Prepay program. SDG&E asserts that the Prepay program will provide an additional payment and energy management option for customers, allowing customers the ability to manage their energy usage by prepaying for energy usage prior to consumption.[1]

DRA proposes the provision of customer budget management tools in lieu of SDG&E's Opt-in Prepay program. DRA's proposed budget management tools would include all the account management and notification features that SDG&E's Prepay program would offer. DRA's proposed tools would be open to all customers but do not come with the downside of significantly reducing the current legally required notice period for a service disconnection.

Clearly, SDG&E's main objective in offering a Prepay option is to reduce its bad debt (or uncollectibles). However, the Prepay program comes with the harsh consequence to enrolled customers of potentially more frequent service disconnections, which could be a great public health and safety concern[2]. Furthermore, SDG&E's proposal would allow a customer to be disconnected four days after the prepayment is exhausted, which is much shorter than the legally required minimum notice period.[3]

The account management and notification features that SDG&E proposes to offer to its Prepay customers can be provided without the accompanying

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[1] SDG&E February 2012 Testimony, Chapter 9, DWC-1.

[2] In AB 1X the Legislature declared: "The furnishing of reliable reasonably priced electric service is essential for the safety, health, and well-being of the people of California." Cited in D.02-02-051, finding of fact 1.

[3] See Public Utilities ("PU") Code Sections 779 & 779.1 and Section III.A of this chapter.

automatic disconnection feature. The account management and notification features, as described by SDG&E's Prepay option, became possible due to the installation of advance meter infrastructure (aka "Smart Meters"), which can track customer energy consumption on a daily or even an hourly basis. All of SDG&E's residential customers have invested in the advanced meter infrastructure ("AMI"). Therefore, all residential customers should be given the opportunity to realize the potential benefits of Smart Meter technologies. Customers who choose to use these account management and notification tools will become more energy conscious and better able to manage their budgets. Consequently, the company's uncollectibles also may be reduced. DRA's customer budget management proposal accomplishes SDG&E's Prepay program goals without exposing customers to frequent disconnection penalties.

DRA recommends that the Commission adopt the following account management and notification features for all customers who are interested in budgeting and managing their energy expenditures:

1. Customers should be able to set different budget amount thresholds for notification and the frequency of notification.
2. They should be able to customize the channel on which they wish to receive notifications of account balances. The options should include text message, email, and automated phone call.
3. Account balances should be updated daily. Customers should be able to view their daily balance by logging into their account online using MyAccount, or by dialing into an Interactive Voice Response ("IVR")[4].
4. Customers should be able to make payments using one of several options: 1) 24-hour online payment by linking to a bank account and making payments from the bank account using MyAccount, 2) 24-hour online

[4] Interactive **v**oice **r**esponse, a telephony technology in which someone uses a touch-tone telephone to interact with a database to acquire information from or enter data into the database. IVR technology does not require human interaction over the telephone as the user's interaction with the database is predetermined by what the IVR system will allow the user access to.

service using a credit or debit card via SDGE's processing vendor BillMatrix, 3) by telephone using an automated IVR system, or 4) by cash or check at one of SDG&E's branch offices or Authorized Payment Locations.

II. BACKGROUND

A. SDG&E's Proposal

SDG&E proposes a Prepay program that would be optional for residential customers beginning January 1, 2014. SDG&E states that this program will represent an additional payment and energy management option for customers, allowing customers the ability to manage their energy usage by prepaying for energy prior to consuming it.[5] SDG&E further notes the benefits of its Prepay program option for customers, include: (1) not needing to pay a two-month deposit, (2) not having to pay off prior bad debt before establishing new service and, (3) potential energy conservation.[6] SDG&E requests that the initial adoption rate be limited to 1% of its residential customers during the first period of three years, which would cover 2014 through 2016.[7]

B. UCAN's Motion

On October 25, 2011, UCAN filed a motion arguing, among other matters, that SDG&E's Prepay program is unlawful. UCAN noted that SDG&E's Prepay proposal includes a disconnection policy where the customers would be disconnected if the Prepay account balance drops below zero for four consecutive days, or the customer's balance is at or below -$20.00.[8] UCAN argued that this disconnection policy fails to meet the minimum notice requirements of Sections 779 and 779.1 of the PU Code, is inconsistent with consumer protections required

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[5] SDG&E Feb 2012 Testimony, Chapter 9, DWC-1.

[6] SDG&E Feb 2012 Testimony, Chapter 9, DWC-1.

[7] SDG&E Feb 2012 Testimony, Chapter 9, DWC-6.

[8] UCAN Motion, p.34.

by Section 739.4, and would unlawfully disadvantage Prepay participants in these ways, contrary to Section 453.[9]

C. Assigned Commissioner's Scoping Ruling

On January 18, 2012, the Assigned Commissioner issued a scoping memo and ruling addressing UCAN's motion. In the ruling, the Assigned Commissioner directed parties to address the legal and factual issues for Prepay in this proceeding:

> *Since the Prepay Program is a separate program and has no impact on rate design, there is no reason why the legal and factual issues surrounding this proposal cannot be considered in this proceeding.*[10]

III. DISCUSSION

A. SDG&E's Proposal May Result in Too Many Service Disconnections

SDG&E suggested that it would limit the Prepay program to 1 percent of its customers in the initial stage.[11] SDG&E appears to be implying that it would be harmless for a small fraction of its customers to opt into a Prepay program. Unfortunately, this may not be true.

For non-prepay customers, SDG&E is legally required to provide a 15-day late payment notice, followed by a 48-hour or 24-hour advance notice prior to service disconnection.[12] These requirements provide customers some time to seek funding sources to avoid the actual service disconnection. In contrast, prepay customers could be disconnected within two to four days of when their prepay account balance drops below zero for four consecutive days, or the customer's balance is -$20.00 or below. As noted by TURN, in replying to UCAN's motion:

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[9] UCAN Motion, pp. 34—40.

[10] The Assigned Commissioner's Scoping Memo for A.11-10-002 dated January 18, 2012, at p.8.

[11] SDG&E Feb 2012 Testimony, Chapter 9, DWC-6.

[12] Public Utilities ("PU") Code Sections 779 & 779.1.

> *"Depending on the current tier of the customer's usage and/or whether heating or air conditioning was necessary, a customer could use $20 worth of electricity in a day or two."*[13]

Therefore, the cycle to shut off Prepay customers is so much shorter. Thus, the Prepay program may result in double to quadruple the disconnection rates of non-prepay customers.

The one percent of SDG&E's residential customers that might participate in the Prepay program represents more than 124,000 customers, which is a significant number of customers.[14] SDG&E's latest disconnect rate is about 2 to 3.5 percent.[15] One percent of participating customers would result in about 3,000 to 5,000 disconnections for the year under normal disconnection conditions. However, if these customers are shut off three or four times more often than those on non-prepay rates, we may see more than 10,000 customers being disconnected for this population, which equates to a disconnection rate in the range of 10 percent. Moreover, some customers' service could be shut off more than a few times.

There are also scenarios that could increase the possibility of Prepay customers being disconnected immediately via SDG&E's smart meter remote disconnection.

- If electricity rates spike and customers do not immediately react to manage their usage, the result might be a more rapid depletion of Prepay credit.

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[13] TURN Reply to UCAN Motion, at p.8.

[14] SDG&E has 1,244,624 residential customers. (from 2012 GRC 2, Chapter 3 workpapers Distribution System Determinants.)

[15] Settlement Agreement Between San Diego Gas & Electric Company, Southern California Gas Company, Disability Rights Advocates, The Division Of Ratepayer Advocates, The Greenlining Institute, The National Consumer Law Center, And The Utility Reform Network Resolving Issues In The Residential Disconnection Proceeding (Rulemaking No. 10-02-005), p.5.

- If the number of persons in a customer's household increases or a customer or someone in the household experiences an unexpected illness, and thus consumes much more energy than expected, the Pre-pay credit could be depleted more quickly leaving the customer unprepared to address the exhaustion of prepay funds.

The human cost and risks associated with energy service disconnection are hard to measure. The Prepay program could lead to more and faster service disconnections, creating hardship and increased costs on SDG&E's most vulnerable customers.

B. SGD&E's Prepay May not be Consistent with All Party Settlement Agreement

In September 2010, SDG&E signed an all-party agreement with consumer parties, including DRA and TURN, which established benchmarks for its residential service disconnection rates of 3.44% for CARE-only customers and 2.08% for the residential class as a whole.[16]

The Agreement is effective through December 31, 2013.[17] In addition, Section H of the Settlement provides for the Settling Parties, prior to the expiration of the Agreement, agreeing to meet to discuss the extension, termination, and/or modification of the Agreement, as well as rate case issues beyond SoCalGas' and SDG&E's upcoming GRCs.[18]

It appears that SDG&E is assuming that the Settlement will not be extended since it proposes that its Prepay program start in January 2014. This does not seem to comport with Section H of the Settlement Agreement as described above.

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[16] Settlement Agreement Between San Diego Gas & Electric Company, Southern California Gas Company, Disability Rights Advocates, The Division Of Ratepayer Advocates, The Greenlining Institute, The National Consumer Law Center, And The Utility Reform Network Resolving Issues In The Residential Disconnection Proceeding (Rulemaking No. 10-02-005), p.5.

[17] Ibid.

[18] Id, p13.

C. SDG&E's Prepay Proposal Takes Away Substantial Customer Protections

SDG&E acknowledged that its Prepay proposal may provide a notification period for disconnection that is much shorter than the notification period for traditional post-pay customers.[19]

Unfortunately, that is not the only issue associated with SDG&E's Prepay program. UCAN, in its motion, provides a detailed explanation of how SDG&E's Prepay proposal violates various legal requirements, which are intended to provide customer protections. DRA will not repeat UCAN's legal arguments here. However, DRA lists the specific customer protections below that may be forgone:

- The 15-day notice requirement of Section 779.1(a).[20]
- A 24-hour notice of termination by telephone or in person; or, where such contact cannot be accomplished, a 48-hour notice delivered by mail or in person as required by Section 779.1 (b).[21]
- No disconnection pending investigation, or complaint, or request for extended period for payment as required by Section 779.[22]

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[19] SDG&E Feb 2012 Testimony, Chapter 9, DWC-5.

[20] PU Code Section **779**.1. (a) Every electrical, gas, heat, or water corporation shall allow every residential customer at least 19 days from the date of mailing its bill for services, postage prepaid, for payment of the charges demanded. No corporation subject to this section may terminate residential service for nonpayment of a delinquent account unless the corporation first gives notice of the delinquency and impending termination, at least 10 days prior to the proposed termination, by means of a notice mailed, postage prepaid, to the customer to whom the service is billed, not earlier than 19 days from the date of mailing the corporation's bill for services, **and the 10-day period shall not commence until five days after the mailing of the notice**. (Emphasis added.)

[21] PU Code Section **779**.1. (b) Every corporation shall make a reasonable attempt to contact an adult person residing at the premises of the customer by telephone or personal contact at least 24 hours prior to any termination of service, except that, whenever telephone or personal contact cannot be accomplished, the corporation shall give, either by mail or in person, a notice of termination of service at least 48 hours prior to termination.

[22] Section 779(c) Any residential customer who has initiated a complaint or requested an investigation within five days of receiving the disputed bill, or who has, before termination of service, made a request for extension of the payment period of a bill asserted to be beyond the means of the customer to pay in full within the normal period for payment, shall be given an opportunity for review of the complaint, investigation, or request by a review manager of the corporation. The review shall include consideration of whether the customer shall be permitted to amortize any unpaid balance of the delinquent account over a reasonable period of time, not to

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- Notification to customers facing disconnection of the availability of the California Alternate Rates for Energy (CARE) program and of extended payment plans, before effecting any disconnection of service for nonpayment or inability to pay energy bills in full.[23]

The legislature and the Commission established these important customer protections because energy services are essential[24] and interruption of those services cannot be taken lightly.

D. SDG&E should Offer Customers Budget Tools Rather than a Prepay Program

It is obvious that SDG&E offers its Prepay proposal in order to reduce its uncollectibles since customers would pay prior to consuming energy, and they would be quickly disconnected if they exhausted their payment. The company's exposure to unpaid energy bills would be substantially mitigated. However, this comes with the potential consequence of customers who are disconnected engaging in dangerous pursuits, hence may cause public health and safety hazard.

On the other hand, the various attendant features offered with SDG&E's Prepay program can be independently offered without being limited to the Prepay program framework. SDG&E explained that its Prepay program would come with the following features:

> *"Prepay account balances will be updated daily. Customers will be able to view their daily balance by logging into their account online using MyAccount, or by dialing into the IVR.*

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exceed 12 months. No termination of service shall be effected for any customer complying with an amortization agreement, if the customer also keeps the account current as charges accrue in each subsequent billing period.

[23] PU Code Section 794(3) (A) Provide information about the CARE program and other assistance programs, and attempt to qualify customers for CARE, and provide information about individual payment arrangements that allow customers to pay the amounts due over a reasonable period of time, not to exceed 12 months, and attempt to enroll customers in a payment arrangement program, before effecting any disconnection of service for nonpayment or inability to pay energy bills in full.

[24] In AB 1X the Legislature declared: "The furnishing of reliable reasonably priced electric service is essential for the safety, health, and well-being of the people of California." Cited in D.02-02-051, finding of fact 1.

Customers will also be able to customize the channel on which they wish to receive notifications of account balances. The options include text message, email, and automated phone call. Customers will be able to set different amount thresholds for notification. For example, the customer could choose to be notified via text message when the balance reaches $20. A customer will also receive notification when his or her account balance reaches zero or below. Prepay customers will be able to make payments using one of several options: 1) online by linking a bank account and making payments from the bank account using MyAccount, 2) online by using a credit or debit card via SDG&E's payment processing vendor BillMatrix, 3) by phone using the automated IVR system, or 4) by cash or check at one of SDG&E's branch offices or Authorized Payment Locations."[25]

With the deployment of AMI, the above-mentioned SDG&E Prepay account management and notification features can be provided to all customers with installed Smart Meters even if they are not offered as a Prepay option. All SDG&E residential customers are paying for the AMI investment, so it is essential for them to be able to have the opportunity to reap the benefits that can be realized through AMI.

SDG&E suggested that the majority of customers who have signed up for existing Prepay programs are satisfied with the option and have accomplished significant energy conservation.[26] However, before trying the Prepay program, DRA recommends that SDG&E provide the budget tools that would have been associated with the Prepay program without the harsh disconnection policy. The customers could choose to establish a monthly (or weekly) budget and be notified if they do or are likely to miss their set budget goals. All the notification options and payment alternatives offered by the Prepay proposal would be applicable. SDG&E also should train its customer service representatives to alert customers

[25] SDG&E Feb 2012 Testimony, Chapter 9, DWC-4.

[26] SDG&E Revised Testimony, DWC-1 & 2.

about these budget tool options, especially customers who are in imminent danger of service shut offs.

If the customers become more conscious about their energy consumption and costs, and take active steps to reduce consumption or to make prompt payments, SDG&E can achieve its goals in reducing disconnections and bad debt without risking customers' safety or disconnecting essential services unnecessarily. Furthermore, if the customers become accustomed to such a system, they can be educated to become more responsive to time-varying rates and other demand response programs.

IV. CONCLUSION

DRA recommends that that SDG&E provide account management and notification tools to all smart meter customers who are interested in budgeting and managing their energy expenditures. The customers should be able to set different budget amount thresholds for notification and the frequency of notification. SDG&E should allow the customers to customize the method (i.e., text message, email, and automated phone call) on which they wish to receive notifications of account balances. In addition, the account balances should be updated daily, and the customers should be able to view their daily balance by logging into their account online using MyAccount, or by dialing into an IVR. Finally, the customers should be afforded payment options including 1) 24-hour online payment by to linking a bank account and making payments from the bank account using MyAccount, 2) 24-hour online use of a credit or debit card via SDGE's processing vendor BillMatrix, 3) Contact by telephone using an automated IVR system, or 4) Payment by cash or check at one of SDG&E's branch offices or Authorized Payment Locations.

APPENDICES
STATEMENT OF QUALIFICATIONS

QUALIFICATIONS
OF
LOUIS IRWIN

Q.1 Please state your name and business address.

A.1 My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Division of Ratepayers Advocates.

Q.3 Please describe your educational and professional experience.

A.3 I have a Master of Arts in Economics from the University of Colorado at Boulder with a focus on environmental, energy and urban issues and a Master of Public Administration from the JFK School of Government in Cambridge. My thesis, while at C.U. Boulder, focused on natural resource scarcity and pricing. Both degrees included coursework in finance and economics that I find relevant to this case. I also have a Bachelor of Arts in Psychology from U.C. Berkeley with a focus on organizational and business psychology applications. While at the U.C. Berkeley University Students Cooperative Association, I held four elected, paid positions including being on the Judicial Board, the General Board (which decided such matters as whether or not to buy additional property) and the Capital Improvements Committee. Since joining DRA in 1999, I have worked on a variety of energy related issues ranging from distributed generation to cost of capital cases. More recently, I have worked on marginal cost and revenue allocation aspects of general rate cases. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates, a specialist in these areas.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am sponsoring testimony on marginal distribution demand and customer access cost issues (Chapter 3).

Q.5 Does this complete your testimony?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF
DEXTER KHOURY

Q.1 Please state your name and business address.

A.1 My name is Dexter Khoury. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2 By Whom are you employed and what is your job title?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst V in the Electricity Pricing and Customer Programs Branch of the Division of Ratepayer Advocates (DRA).

Q.3 Will you please briefly state your educational background and experience?

A.3 I graduated from the University of California at Santa Barbara with a Bachelor of Arts in Economics in 1977. I received a Master of Arts degree in Economics from San Francisco State University in 1987.

I joined the staff of the California Public Utilities Commission in 1986 and have worked in the Special Economics Branch, The Telecommunications-Operations and Cost Branch, The Energy Rate Design and Economics Branch, the Monopoly Regulation Branch, the Electricity Resources and Pricing Branch, and The Electricity Pricing and Customer Programs Branch of DRA. I have worked on numerous electric and gas rate design and cost allocation proceedings.

Q.4 What testimony are you sponsoring in this proceeding?

A.4 I am responsible for Chapter 5, Residential Rate Design.

Q.5 Does this complete your testimony at this time?

A.5 Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY
OF Robert Levin

Q.1. Please state your name and business address.

A.1. My name is Robert Levin. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the State of California at the California Public Utilities Commission (CPUC) as a Senior Regulatory Analyst in the Division of Ratepayer Advocates (DRA).

Q.3. Please state your educational background and experience.

A.3. I have a Ph.D. in Operations Research and an M.A. in Mathematics from the University of California, Berkeley, and a B.A. in Mathematics from U.C.L.A.

I was employed by PG&E for 24 years in various professional capacities in the areas of resource economics, capacity planning, marginal cost studies, and project cost-effectiveness evaluation.

I joined the Commission staff early in 2008. Since then, I have worked primarily on gas AMI and electric rate design proceedings. I sponsored policy and economic analysis testimony in the SoCalGas AMI proceeding (A.08-09-023), in PG&E's 2011GRC Phase 2 (A.10-03-014) and in SCE's 2012 GRC Phase 2 (A.11-06-007) proceedings.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapters 1, 2, and 6 of DRA's prepared testimony.

Q.5. Does this complete your testimony?

A.5. Yes.

QUALIFICATIONS OF
LEE-WHEI TAN

Q.1. Please state your name and business address.

A.1. My name is Lee-Whei Tan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst V in the Electric Pricing and Consumer Program Branch of the Division of Ratepayer Advocates ("DRA").

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Science Degree in Chemistry from National Tsing Hua University in 1979 (Taiwan) and a Master of Arts Degree in Economics in 1986 from San Francisco State University.

In July 1986, I joined the Fuels Branch of the Division of Ratepayer Advocates where I sponsored testimony relating to utilities fuel management practices. I transferred to the Special Economics Branch in July 1987 and was involved in the benchmarking of computer programs (ELFIN, PCAM, PROMOD). In April 1988, I joined the Economics and Energy Rate Design Branch where I was assigned marginal costs and rate design for gas and electric cases. In 2001, I was assigned to the Telecommunications Branch of ORA, where I was assigned to work on telephone utility cases, such as New Regulatory Framework proceedings, mergers, and Public Utilities Code §851 proceedings.

I joined the Electric Pricing and Consumer Program Branch in July, 2009, and have been assigned to work on the revenue allocation and project coordination for

San Diego Gas and Electric ("SDG&E") Critical Peak Pricing Application and Pacific Gas and Electric Company's ("PG&E") 2011 GRC Phase 2 Filing.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 4 on "Revenue Allocation" and Chapter 7 on "Prepay Program" of DRA's prepared testimony in SDG&E's 2012 GRC Phase 2 Filing.

CERTIFICATE OF SERVICE

I hereby certify that I have on this date served a copy of **TESTIMONY ON SAN DIEGO GAS & ELECTRIC COMPANY'S 2012 GENERAL RATE CASE, PHASE 2 A.11-10-002** to all known parties by either United States mail or electronic mail, to each party named on the official attached service list in **A.11-10-002**:

I hand-delivered a hard copy to the assigned Administrative Law Judge's mail slot.

Executed on **May 18, 2012** at San Francisco, California.

/s/ CHARLENE D. LUNDY
Charlene D. Lundy

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