Docket:	:	A.10-07-009
Exhibit Number	:	DRA-1
Commissioner	:	Michael Peevey
Admin. Law Judge	:	Jessica T. Hecht
DRA Project Mgrs.	:	Chris Danforth, Lee-Whei Tan
DRA Witnesses	:	Cherie Chan Louis Irwin Dexter Khoury Eric Nelson Dale Pennington Lee-Whei Tan

DIVISION OF RATEPAYER ADVOCATES
CALIFORNIA PUBLIC UTILITIES COMMISSION

Testimony on San Diego Gas and Electric's Dynamic Pricing Application

San Francisco, California
February 18, 2011

MEMORANDUM

This report was prepared by the Division of Ratepayer Advocates ("DRA") of the California Public Utilities Commission ("Commission") in San Diego Gas and Electric's ("SDG&E's") 2010 Dynamic Pricing proceeding. In this docket, the applicant requests: (1) Time-variant pricing and default dynamic rate proposal for its small non-residential customers; (2) Optional ("opt-in") time-variant pricing proposals for its residential customers, including a dynamic pricing rate; and (3) The funding necessary to implement the dynamic pricing rates and to conduct customer education and outreach.

In this report, DRA presents its analysis of the applicant's request and its associated recommendations. DRA does not find the majority of the funding that SDG&E requests to be adequately supported with outreach plans or Information Technology ("IT") upgrade plans. It believes that SDG&E's critical peak pricing ("CPP") proposals are too complex for small customers to understand. DRA recommends beginning with simpler time-of-use ("TOU") rates in order to give customers time to adjust to the concept of time-varying rates ("TVR"). SDG&E's application and testimony are also deficient in not providing an estimate of the demand response benefits that can be expected from the new rates it proposes.

Chris Danforth and Lee-Whei Tan served as DRA's project coordinators in this review, and are responsible for the overall coordination in the preparation of this report. DRA's witnesses' prepared qualifications are contained in Appendix A of this report.

List of DRA Witnesses and Respective Chapters

Chapter Number	Description	Witness
1	DRA Time Variant Rate Policy Positions	Lee-Whei Tan
2	Residential Rate Design	Dexter Khoury
3	Small Commercial Rate Design	Cherie Chan
4	Analysis of Project Benefits	Louis Irwin
5	Information Technology, Outreach & Education Costs	Dale Pennington/ Eric Nelson
6	Facilities and Operations	Louis Irwin
7	Revenue Requirements and Cost Allocation	Lee-Whei Tan

CHAPTER 1

DRA TIME-VARIANT RATE POLICY

LEE-WHEI TAN

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CHAPTER 1

DRA TIME-VARIANT RATE POLICY

Witness- Lee-Whei Tan

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Division of Ratepayer Advocates' ("DRA") policy positions and summarizes DRA's recommendations regarding San Diego Gas and Electric Company's ("SDG&E") dynamic pricing proposals. SDG&E requests authority to provide dynamic pricing options including PeakShift at Home ("PSH") and PeakShit at Work ("PSW") to virtually all of SDG&E's customers, including its estimated 1.2 million residential and 120,000 small nonresidential customers.[1]

A. SDG&E's Dynamic Pricing Application Should Be Dismissed.

DRA recommends that the Commission allow SDG&E to move forward with its Peak Time Rebate ("PTR") Program, which was approved in its last Rate Design Window ("RDW") Application.[2] In this Application, SDG&E proposes to modify the PTR, and DRA in general supports the changes.[3] However, DRA recommends that the Commission dismiss the rest of SDG&E's Dynamic Pricing ("DP") Application, which deals with its Critical Peak Pricing ("CPP") Options[4] and associated cost recovery requests. SDG&E should be required to re-file its case after it has conducted further analysis to address the deficiencies identified by DRA. Alternatively, the Commission

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[1] SDG&E Chapter 1, p.JSV-1. SDG&E stated that the funding and resources being requested in this Application will also allow SDG&E to implement its approved default Critical Peak Pricing ("CPP-D") to its estimated 22,000 medium nonresidential customers (*i.e.*, customers with maximum demand between 20kW and 200 kW), which will be provided with Smart Meters and twelve months of interval energy usage data over the next couple of years.

[2] D.09-09-036.

[3] DRA's analysis and proposals on Residential PTR is presented in Chapter 2.

[4] SDG&E names its CPP tariffs "PeakShift at Work" (or "PSW") for small business customers and "PeakShift at Home" (or "PSH") for residential customers.

can direct SDG&E to file supplemental testimony in this proceeding to addresses these deficiencies.

DRA finds SDG&E's current application deficient in two significant areas:

1. SDG&E's application and testimony do not reflect sufficient planning and analysis to support the budgets requested for its information technology ("IT") system design and outreach and education program. Missing is a clear roadmap, with its IT system and project interdependencies delineated, to prevent duplication of efforts and costs. SDG&E also failed to conduct a cost comparison to see if other alternatives, such as buying commercial off-the-shelf products ("COTS"), or third party hosted solutions, would be more cost-effective than maintaining its legacy system. For outreach and education activities, SDG&E did not establish clear objectives and develop strategies to measure performance against those objectives.
2. SDG&E has not quantified the benefits associated with this proposal that are incremental to the demand response benefits that SDG&E used to justify the cost of its Advanced Metering Infrastructure ("AMI) in A05-03-015.

Without more detailed information, the Commission cannot assess the reasonableness of the costs requested by SDG&E. Without an analysis of benefits, it is difficult to determine whether SDG&E's cost request is justified.

In the AMI proceeding, DRA did not find SDG&E's initial business case to be cost effective. SDG&E and the other parties had to make some modifications and added somewhat speculative environmental benefits to make the benefit positive. DRA performed an analysis of the incremental benefits of SDG&E's dynamic pricing proposals in this application. As described in Chapter 4, DRA found that the benefits of SDG&E's rate proposals are less than those assumed in the AMI business case. The results call into question whether the AMI proceeding, in retrospect, overestimated the DR benefits. Before spending another $118.1 million, this issue must be investigated. DRA feels uncomfortable spending $118.1 million to produce at best $50 million dollars benefits -- the same level of benefits that were estimated in the AMI proceeding. DRA believes it would be more prudent to begin with a simple TOU rate that can be implemented with a minimal level of incremental funding. It's possible that a higher customer acceptance rate, coupled with the fact that TOU rates impact ten times the number of hours than do either PTR or PSW, may lead to even higher benefits than what is achievable with dynamic pricing. But whether or not this is true currently remains unknown. For this reason, DRA has recommended TOU pilot programs in Chapter 5 before we throw $118 million into a project that may not provide real benefits.

Furthermore, PG&E and SDG&E's recent experience with implementing CPP for large commercial and industrial ("C&I") customers, coupled with the current economic and market conditions, suggest the need to provide customers more moderate time-varying rate ("TVR") options. Transitioning customers from flat rate structures to voluntary TVR,[5] which are easier to understand, such as time-of-use ("TOU") rates, have the greatest probability of success in the short run.

DRA acknowledges that the rate design it presents in Chapter 3 may not achieve the benefits assumed in the AMI business case either. However, DRA's rate design proposals should accomplish some of the AMI goals, such as peak load reduction and emission reduction, with little increase in costs relative to those adopted in the AMI proceeding. If SDG&E believes its AMI expenditures were not sufficient to implement a simple TOU rate, this raises the question of whether the AMI deployment itself was cost-effective. If, in hindsight, it was not, then DRA believes it is best to view the AMI investment as a sunk cost. Accordingly, going forward, whatever rate design is adopted should be one that is effective and requires the least amount of money to implement. Such a rate design would likely be a TOU rate. Minimizing costs going forward will help prevent "throwing good money after bad",

The Commission's overarching policy objectives have been to ensure that adequate, reliable, and reasonably priced electrical power is provided. These objectives can only be achieved through policies, strategies, and actions that are cost-effective and

[5] Time-variant rates are defined as rates varying by time of day and season, such as summer on-peak, which for SDG&E applies to summer months (May 1 through October 31) day time hours between 11 a.m. to 6 p.m.; winter off-peak applies to winter months (November 1 through December 31, and January 1 through April 30) from 10 p.m. to 6 a.m.

environmentally sound for California's consumers and taxpayers.[6] The Commission also emphasized that utility activities must be taken with clear recognition of cost considerations and trade-offs to ensure that reasonably priced energy is delivered to all Californians.[7] Utility rate options must also be undertaken in a way that customer acceptance is obtained. Unfortunately, SDG&E's proposal does not meet these objectives. SDG&E's rates are already high in comparison to other states and other California's investor owned utility's ("IOU's") rates. Neither SDG&E nor its ratepayers can afford projects that are not cost-effective.

B. DRA's Detailed Recommendations

In this section, DRA presents in more detail its specific recommendations. In regard to overall funding, DRA recommends that:

1. The Commission dismiss SDG&E's request to fund its CPP program.
2. Future rate proposals involving substantial implementation costs be accompanied by a detailed cost / benefit analysis, including an analysis of the comparative benefits of non-rate design, such as energy efficiency program options.
3. If the Commission grants partial funding for SDG&E's request, the implementation costs be allocated to customer classes using the generation equal percent marginal cost ("EPMC") method in order to be consistent with the Commission's cost causation principles.
4. Post-2015 O&M costs related to time-variant rate implementation costs be consolidated and determined in the General Rate Cases ("GRC") to avoid piece-meal revenue requirements.

In regards to IT, Outreach and Education, DRA recommends:

1. SDG&E should propose a first phase of effort focused on:
    a. A pilot program for TOU rates:
        1. The pilot program should provide for at least two TOU pilot rate structures, one with prices that are as close as possible

[6] Adopted in May 8, 2003. The Commission called this a "post-energy crisis call-to-action" plan.

[7] Ibid.

to the underlying marginal cost of service,[8] and one that has less of a range between peak and non-peak rates.

2. The pilot program should include a customer outreach and education plan to support the TOU rates.
3. SDG&E should assess the feasibility and cost of using third-party hosted IT providers for the TOU pilot to determine if it is a cost-effective alternative.

b. IT system enhancements required to support a TOU rate structure for SDG&E's full customer base.

2. SDG&E should employ cost-effective customer outreach methods to promote TOU rate options. Examples of such methods include:

   a. Clear prices and schedules for the TOU rates printed on bills and on magnets that customers would place on major appliances to influence their behavior changes.

   b. Press releases, notifying local TV and print news agencies for the new rates.

3. SDG&E should develop a clear roadmap for its IT systems with project interdependencies delineated to show how new initiatives fit into the overall end-vision for SDG&E's information technology capabilities. This should show the timeline for the IT projects required for this initiative and how they fit into the SDG&E overall IT plan.

4. SDG&E should perform cost comparison studies to assess the relative costs of continually upgrading its legacy systems versus deploying commercial off-the-shelf ("COTS") packages.

5. SDG&E should define a formal process for ensuring that there are no overlaps in funding between rate cases for IT. DRA recommends that an internal, independent third-party (outside IT) should govern/administer this process.

In regard to residential rates, DRA's recommendations are as follows:

1. SDG&E's residential PTR program should be implemented in an effective manner as rapidly as possible. This program should be fully studied and evaluated for a minimum of two years.

[8] The rates should cover public purpose programs or any other rates mandated by the Commission.

2. If SDG&E implements optional residential CPP or PSH rates, the CPP or PSH rate should contain an event period adder of fifty cents per kWh.

3. SDG&E's proposal to reduce PTR credits should be adopted when the decision for this application becomes effective.

4. SDG&E should clearly display and describe its rates. If SDG&E implements new PSH and TOU rates, it should show fully bundled rates for these optional rates on the PSH or TOU tariff book page to avoid customer confusion.

5. If the Commission authorizes SDG&E to implement an optional three-tier TOU or Time of Day ("TOD") rate, this TOD rate should be carefully monitored to ensure revenue neutrality. In its annual true-up filing, SDG&E should identify revenue shortfalls caused by customers transitioning from flat rates to TOU rates.

In regard to small commercial rates, DRA recommends that the Commission:

1. Direct SDG&E to begin with a voluntary TOU rate schedule designed specifically for small business customers (under 20 kW in load).

2. Order SDG&E to more thoroughly investigate the effects of time-varying pricing on small commercial customers giving consideration to how customers will react to such pricing prior to rolling it out to all customers.

II. SDG&E'S PROPOSALS

SDG&E stated that its proposals are guided by several Commission decisions: SDG&E's 2008 GRC, Phase II (D.08-02-034);[9] PG&E's Dynamic Pricing (D.08-07-045);[10] SDG&E's 2008 RDW (D.09-09-36);[11] and PG&E's 2009 Peak Day Pricing ("PDP") proceeding (D.10-02-032).[12]

SDG&E plans to implement its PSW rate prior to the summer of 2013. Below is a brief timeline of SDG&E's Dynamic Pricing Proposal[13]:

[9] A. 06-12-009.

[10] A. 06-03-005.

[11] A. 08-12-014.

[12] A. 09-02-022.

[13] SDG&E Chapter 1, p.JSV-12.

2010 - 2011	Customer/Stakeholder Research, Systems Design and Build
2011 - 2012	Launch Customer Education and Outreach Effort
2012 - 2013	Test and Implement Systems
2013 - 2014	Roll-out Dynamic Rate to Customers Over a 12-month Period

In addition to the dynamic rate proposals, SDG&E is seeking the following incremental costs in order to implement its rate proposals:

Summary of Implementation Costs[14]

Costs	**2010 ($1,000)**	**2011 ($1,000)**	**2012 ($1,000)**	**2013 ($1,000)**	**2014 ($1,000)**	**2015 ($1,000)**	**Total ($1,000)**
Capital							
Outreach & Education	-	$954	$1,071	-	-	-	$2,025
IT	$2,560	$18,444	$16,632	$7,228	-	-	$44,864
Operations	$115	$313	$319	$42	-	-	$ 789
Facilities	-	$4,036	-	-	-	-	$4,036
AFUDC[15]	$56	$1,261	$2,020	$603	-	-	$3,941
Total Capital	**$2,731**	**$25,008**	**$20,083**	**$7,831**	**-**	**-**	**$55,654**
O&M							
Outreach & Education	$290	$3,001	$4,297	$7,318	$6,366	$4,572	$25,844
IT	$844	$96	$1,389	$3,592	$4,163	$4,341	$14,425
Operations	$464	$1,268	$3,173	$5,397	$4,900	$4,068	$19,270
Facilities	$102	$714	$734	$755	$288	$295	$2,888
Total O&M	**$1,700**	**$5,079**	**$9,593**	**$17,062**	**$15,717**	**$13,276**	**$62,427**
Total Cost	**$4,431**	**$30,087**	**$29,676**	**$24,893**	**$15,717**	**$13,276**	**$118,081**

III. DISCUSSION

DRA assessed SDG&E's application in the following ways: 1) Does SDG&E present a rigorously developed business case for its plan that will lead to a cost-effective investment for such a project? 2) Will the program design be successful in achieving both customer acceptance and peak load reduction? On both counts, DRA concludes that SDG&E's application is deficient.

SDG&E's dynamic pricing application is based on the premise that the Commission still desires to move all customer classes to dynamic rates in the near future. With that belief, SDG&E failed to conduct a cost-benefit analysis to justify ratepayer funding of CPP costs. In addition, its proposals largely follow the directions of the

[14] SDG&E Chapter 1, pp.JSV-14-15.

[15] AFUDC (Allowance for Funds Used During Construction) per witness Myers (Ch. 6).

Commission's decisions establishing the dynamic pricing policy guidelines and timelines for PG&E.[16] However, there is empirical evidence that customer acceptance of dynamic pricing, like CPP, is low even for the larger, more sophisticated customers. Not to mentions that current economic and market conditions also warrant a modification of this policy direction.

A. Dynamic Pricing Background

Dynamic Pricing tariffs began to attract significant attention in 2003, when California had just experienced an energy crisis leading to a serious electricity supply shortage, in turn causing power blackouts. At the time, it was urgent for the Commission to intervene to mitigate the energy demand and supply imbalance in order to alleviate the energy shortage. The Energy Action Plan ("EAP") called for an immediate response, and led the Commission to direct the investor-owned utilities ("IOU"s) to establish many energy efficiency programs, to build or procure new resources, to construct more transmission lines, and to deploy an advanced meter infrastructure ("AMI").[17]

The Commission started implementing the energy action plans ("EAP" I & II) issued around 2003 – 2005. The plans suggested that dynamic pricing tariffs would be useful tools to help address California's energy shortage problems.[18] Its 2003 Vision statement noted that electric customers should have "the ability to increase the value derived from their electricity expenditures by choosing to adjust usage in response to price signals".[19] These price signals would be enabled with advanced meters. [20] The EAP II concludes that "[w]ith the implementation of well-designed dynamic pricing

[16] SDG&E Chpater 1, p. JSV-7.

[17] EAP II, p.2.

[18] *Id.*, p.4.

[19] "California Demand Response: A Vision for the Future (2002-2007)," referred to here as the 2003 Vision Statement, was attached to D.03-06-032 as Attachment A.

[20] "California Demand Response: A Vision for the Future (2002-2007)," referred to here as the 2003 Vision Statement, was attached to D.03-06-032 as Attachment A.

tariffs and demand response programs for all customer classes, California can lower consumer costs and increase electricity system reliability."[21]

The Commission identified CPP and real time pricing ("RTP") as dynamic pricing tariffs.[22] The Commission also directed that dynamic rate options be offered to all customer classes, and that dynamic rates be developed in the IOUs' rate design cases. In 2008, the Commission issued an implementation plan for Pacific Gas & Electric ("PG&E") that provided dynamic rate design principles and established a timeline for PG&E to implement such rates, starting with the largest customers first.[23]

B. Customer Responses to Dynamic Pricing

SDG&E has offered CPP to its large C&I customers since 2008, but the total number of customers opting out continue to increase. By the end of 2010, the opt-out rate reached almost 40%.[24]

PG&E's large commercial and industrial customers were scheduled to default to CPP in May 2010. Despite an intensive education campaign through utility account representatives, and the fact that large customers had had prior direct experience with time-of-use rates, 62% of PG&E's Large C&I Customers have either opted out or dis-enrolled in CPP. PG&E is concerned it cannot offer its approximately 500,000 small business customers the same level of intensive outreach and education as it offered to its largest C&I customers due to the lack of scalability of personalized outreach. This makes it likely that the small business customer adoption rates would be even lower than those of the Large C&I customers. As a consequence, PG&E recently filed a petition to delay implementation of its dynamic rate programs for its small business and residential customers.

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[21] *Id.*, p. 4.

[22] D.08-07-045, mimeo, p.6.

[23] D.08-07-45, mimeo, Attachment B.

[24] DRA Data Request – DRA-05, SDG&E Response 4: November 23, 2010.

In its Petition, PG&E stated that the key to successful implementation of dynamic rates is customers' engagement in long-term, sustainable behavior change, and such engagement begins with:[25]

1) A customer's understanding of the benefits and capabilities of his/her SmartMeter™ device, followed by
2) The introduction of TOU rates to build awareness of energy costs at different times of the day, leading to
3) Participation in CPP to reinforce and develop behavior changes begun during the TOU period.

PG&E found it critical to request an extension in the timeline for small business customers in order to promote long-term, sustainable support and behavioral change by its customers.[26] SDG&E's CPP proposal faces the exact same challenges. In general, DRA supports PG&E's petition and its underlying premise that it is wiser to implement simpler time-variant rates first rather than abruptly transition from a flat rate to CPP. DRA, the California Small Business Association and Small Business Roundtable (Joint Parties or "JPS") also filed a petition in the PG&E proceeding to support a delay of CPP. The JPS petition recommended a gradual and measured implementation of TOU rates for the mass market, given that they are easier to understand than dynamic rate designs.

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[25] PG&E Petition to Modify D.10-02-032., p.2.

[26] PG&E Petition to Modify D.10-02-032, p.2, PG&E asked for the following extension:

- For small- and medium-sized commercial and industrial (C&I) customers, PG&E proposes that these customers first default to mandatory TOU rates beginning on November 1, 2012 (rather than default to PDP on November 1, 2011, as currently required), and then default to PDP (including TOU) no earlier than March 1, 2014.
- For small- and medium-sized agricultural customers, PG&E proposes that these customers begin to default to mandatory TOU on March 1, 2013, rather than February 1, 2012, as currently required.
- For residential customers, PG&E proposes to eliminate the requirement to implement a new residential PDP rate on November 1, 2011, and, instead, to retain SmartRate™ as an option for residential customers until residential dynamic pricing options are considered again by the Commission.

C. Align Customer Interests with Commission Policy Objectives

1. Reasonably-Priced Energy Rates

As mentioned earlier, the Commission's overarching policy objectives have been to ensure that ratepayers have adequate, reliable, and just and reasonable rates for electrical power.[27] Therefore, it is important that the cost of implementing the rates should be less than the benefits they will achieve.

SDG&E's CPP funding plan is deficient in this regard. SDG&E has not conducted a cost-benefit analysis to assess whether the incremental costs of implementing CPP are less than the resulting benefits. DRA's analysis calls into question the cost effectiveness of SDG&E's DP proposals because it demonstrates that SDG&E's CPP proposal would reduce the benefits assumed in the AMI case. This is discussed in Chapter 4 of DRA's testimony. Moreover, SDG&E's IT and outreach/education proposals cannot be validated, as detailed in Chapter 5. Furthermore, if SDG&E's dynamic pricing plan fails to obtain substantial customer buy-in, a large amount of ratepayer expenditures would be made without accomplishing adequate returns. Instead, there would be many unhappy and cynical customers, presenting the Commission and the utilities potentially insurmountable obstacles to implementing other new rate programs.

2. Current Market and Economic Conditions

Today, the Commission is dealing with a different scenario than it faced in the post-energy-crisis situation. We no longer have an "energy crisis" caused by an energy supply shortage. To the contrary, California as a whole has more than adequate capacity to provide its energy needs for the next several years. With IOUs procuring and/or building more power plants, the expected high and fluctuating wholesale market prices have been substantially dampened. As PG&E stated in its General Rate Case, Phase 3, testimony on RTP:

[27] Adopted in May 8, 2003. The Commission called this a "post-energy crisis call-to-action" plan.

> PG&E recognizes that CPUC and California Energy Commission ("CEC") policy staff, academic economists and policy experts, and a succession of both CPUC and CEC commissioners have attached great expectations to the future of RTP for at least the last 15 years. PG&E cautions, however, that the first several quarters of day-ahead hourly CAISO prices have shown *very* little variation outside of the range of ordinary time-of-use ("TOU") generation energy charges (much less, at the price levels of 50 cents to $1.00 per kilowatt-hour ("kWh') and more that will be effective under the new PDP tariffs), with only infrequent instances of even moderately higher-priced or lower-priced blocks of hourly prices**.** There has been very little incorporation of capacity costs to be observed in the first several quarters of day-ahead hourly CAISO prices, given that in the entire summer 2009 hourly prices reached even 10 cents per kWh on just two or three occasions**.** While the general nature of the day-ahead hourly CAISO prices observed to date are broadly reflective of a stable wholesale market, PG&E cautions that retail RTP tariffs linked to these prices are likely to provide customers with less dramatic price incentives to shift or reduce load than might first have been envisioned for the program.

In fact, the Commission has started to recognize these effects. In its 2008 EPA II update document, the Commission stated:

> Therefore, if consumers were required to pay more for electricity at peak times, it would produce an incentive to reduce use during those periods. However, some of our other policies are potentially dampening this effect. In our efforts to ensure reliability and electric resource adequacy, ***we are requiring reserve margins and capacity under contract that may reduce the cost increases and volatility of prices at peak times***.[28]

These circumstances will reduce the likely benefits from dynamic pricing programs.

Furthermore, California and the nation are facing the most severe recession since the great depression, and many households and businesses have encountered significant

[28] EAP II Update, 2008, at pp.12-13. Emphasis added.

financial difficulties. In its November 2010, the Legislative Analyst's Office ("LAO") summarized the state of the California economy as follows:

> The National Bureau of Economic Research has determined that the national recession that began in December 2007 ended in June 2009. It was the longest recession since World War II and the most severe downturn since the Great Depression. The 2007-2009 recession was precipitated by the implosion of overheated housing markets in California and throughout the United States, the resulting balance sheet deterioration of financial firms and households, and the near collapse of world credit markets.[29]

LAO forecasts the unemployment to remain high, at 11.9 percent in 2011, 10.5 percent in 2012, 9.1 percent in 2013, and 8.4 percent in 2014. Personal income in California is not expected to return to pre-recession levels until 2014. This means that, for many customers, their overall financial state will continue to be in distress for at least the next three years. Confronting them with complicated energy price options will only frustrate their daily lives, and potentially worsening their financial situation caused by unpredictable CPP events.

3. Customer Learning Curve for Dynamic Pricing is Steep

It has become apparent that a few more years may be required for the IOUs to gain sufficient experience with the new AMI systems to effectively make use of them. Also, it will take time for customers gain confidence in the new meters, and for the associated enabling technology to become sufficiently mature to effectively assist customers in managing their energy usage.[30]

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[29] In 2009, personal income in California dropped 2.4 percent—the first annual decline since 1933. (2011-12 California Budget: California's Fiscal Outlook, Legislative Analyst Office, November 2010, p. 13 at http://www.lao.ca.gov/reports/2010/bud/fiscal_outlook/fiscal_outlook_2010.pdf. (emphasis added).)

[30] In its Petition to Modify ("PFM") D.07-04-043 filed on Sept. 10, 2010, SDG&E states "The ZigBee® Smart Energy Profile v.2.0, a standards-based firmware enabling the mass deployment of devices linking to smart meters, is under development and should be available during the fourth quarter of 2010. As this work is completed, SDG&E will be selecting a vendor for a limited (1000-installation) pilot to be conducted during the first half of 2011. Based on the results of the pilot program, the possible reissuance

(continued on next page)

PG&E mentioned, in its PFM, it conducted focus group research in May 2010 with large C&I and large agricultural customers. This information revealed that Peak, Partial-Peak and Off-Peak pricing may be familiar to these large customers. Yet, for customers to continue participating in the CPP, its customers need to see the benefits of their consumption changes in their monthly energy statements, and this awareness will be key to the success of the dynamic pricing program.

PG&E further noted that it is essential to allow small customers to have adequate experience with TOU rates so that they will begin to see the impacts of their energy use, during different times of the day, on their bills. Moreover, additional time is needed to prepare the customers to develop new energy use patterns that will enable them to adapt to dynamic rates triggered by peak events.

The Commission has not set a timetable for SDG&E's CPP rates for small business and residential customers. Yet, SDG&E proposes to default small business on CPP before the summer of 2013. This is too hasty. DRA is concerned that small customers simply do not have the flexibility to adjust in their business operations to take adapt to CPP in this recession. They will not have enough money to invest in energy management devices enabled by AMI. Nor are stores or restaurants likely to risk losing business by raising the air conditioning setting on very hot days. This problem is exacerbated by the fact that SDG&E has not provided a relatively benign opt out alternative, as has PG&E.[31]

In contrast to CPP, TOU rate structure is easier to understand, more predictable, and less disruptive to small businesses. Therefore, it makes sense to transition small business customers to TOU first. Even this can be a daunting task because the majority of small business customers have not previously been exposed to time-varying rates of

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of requests for proposals may be required, with mass deployment planned for later in 2011 and continuing into 2012, assuming the commercial availability of suitable technologies in the quantities required." However, at DRA's field visit on Dec. 10, 2010. SDG&E noted that ZigBee v.2.0 is still under development. It is not clear when it will become fully reliable for mass market deployment.

[31] This is further explained in Chapter 3.

any form. In addition the advance notification aspect of PDP will add significant costs to utility operations for the relatively few times that the critical peak events may occur. On the other hand, TOU pricing does not require the development of an interactive IT notification architecture.

To assure that the new rate programs will be successful, it is imperative to align customer interests with the CPUC policy goal. A failed program that may cause the utility's rates to increase and may result in energy becoming less affordable to customers, will create further financial stress for businesses. Therefore, the new programs must be cost-effective and have a high probability of gaining significant customer acceptance.

4. Targeted Outreach/Education Coupled with Integrated Energy Solutions to Customers

The Commission has recognized that concerns about the load curtailment impacts on the customers' core businesses have been the largest barrier to their participation:

> The biggest barrier to customer participation in DR is related to concerns that curtailing load would impact the customers' core business functions. To engage customers on DR strategies, IOUs need to first fully understand what these core business functions are and then figure out what load reduction strategies will work within those constraints.[32]

Therefore, it will be critical for SDG&E to establish an interval usage database for each of its customers containing at least one year's worth of data. This will enable SDG&E to analyze the information and correctly explain to customers the effect of TOU pricing in promoting time-varying rates. In addition, this analysis allows SDG&E to target the customers who may be impacted the most and offer extensive support in that regards. SDG&E can use the data to work with customers to explain what tools may be available to assist them to shift load, and to show them the savings they can achieve by employing potentially moderate changes in their operations. The Statewide Process

[32] California Statewide Process Evaluation of Selected Demand Response Programs, Process Evaluations of PG&E, SCE and SDG&E's Critical Peak Pricing and Base Interruptible Programs: Final Report, KEMA Inc., April 2010, p. ES 1-2.

Evaluation cited above also found that helping customers with solutions must continue after signing up customers to dynamic rates.

> [Account Executives] are found to play an important role in assisting customers to identify opportunities to reduce load for DR events. In most cases, it is not enough to sign the customer up to the program, and then hope they will know what to do when an event is called. One rep mentioned that there is too much emphasis on just getting the initial sign-up, and that more education is needed to assist customers with curtailment efforts.[33]

It is crucial that SDG&E rolls out a time-variant rate that will take into account all the factors above so that the plan can be successful and brings benefits to both the utility and the ratepayers.

D. TOU Rates Have Not Been Given an Adequate Chance

In the past, the costs for interval meters were high and were major barriers to promote the TOU rate for the mass market. However, AMI meters make TOU a viable option among the various time-variant rates. The utilities can design TOU rates with moderate price differentiation between on and off-peak as an introductory rate to allow customers getting acquainted with how electricity costs vary depending on when they use it. The utilities can also test more aggressive TOU rates through pilot programs, to determine whether they can accomplish enough load reduction, to be successful. Unfortunately, TOU rates seemed to have been dismissed by the Commission based on the assumption that the demand response ("DR") that can be elicited from TOU is less that from CPP or other dynamic pricing options. While this might be true on a per-participant basis, it may not be true if the number of customers who opt into TOU rates is significantly greater due to a higher acceptance rate than for CPP rates.

Furthermore, the potentially greater energy efficiency ("EE") benefits and greenhouse gases ("GHG") reductions from TOU relative to CPP programs may make them a viable option. The higher EE and GHG benefits of TOU programs come from

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[33] *Id*., p. 2-46.

the fact that they potentially impact customer behavior every summer afternoon, which amounts to roughly 180 days, rather than only on 9 to 15 especially hot days. Regrettably, these economic realities have not been debated before the Commission, in spite of the fact that the EAP II places programs promoting EE higher in the loading order than those that promote DR. Such programs also better link to the EAP II's focus on the importance of dealing with climate changes.

In today's world, one must ask whether it is more important to control gas prices through EE or the cost of new generation supply-side resources through DR. Given the significant efforts undertaken to provide adequate supply reserves to avoid market power, DRA believes that the risk of gas price spikes owing to disruptions in world markets greatly exceeds the risk of returning to the kind of market power evident in the 2001 California energy crisis, which led the Commission to set high priority on DR.

IV. CONCLUSION

DRA recommends the Commission allow SDG&E to move forward with the PTR but dismiss the rest of SDG&E's application dealing with CPP. SDG&E failed to perform cost benefit analysis to justify its request of $118 million for implementing CPP programs. The Commission cannot grant funding for potentially non-cost-effective projects. In addition, SDG&E is deficient in its planning and analysis for the budgets requested for its IT system design and outreach/education business case. As a result, the Commission cannot assess the reasonableness of the costs requested by SDG&E. Moreover, PG&E's and SDG&E's recent experience with implementing CPP for large C&I customers, coupled with the current economic and market conditions, require that the Commission reassess the options for TVR for smaller customers. Transitioning mass customers from flat rate structures to TVR, which are easier to understand, such as TOU rates, have a higher probability of success. TVR are also more likely to gain customer acceptance and are more cost-effective to implement than CPP would be.

DRA's analysis in this case demonstrates that the assumed benefits and customer participation from the AMI cases may be too optimistic. This calls for the Commission to reassess the direction of time-variant rate options. DRA anticipates this to be a long term project. It may require the Commission and the involved parties to vigilantly monitor the progress and make modifications based on customer acceptance and market conditions from time to time.

CHAPTER 2

RESIDENTIAL RATE DESIGN

DEXTER KHOURY

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CHAPTER 2

RESIDENTIAL RATE DESIGN

(Witness - Dexter Khoury)

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Division of Ratepayer Advocates' ("DRA") testimony on residential rate design for SDG&E's Dynamic Pricing Application A.10-07-009.

DRA recommends:

1. SDG&E's residential Peak-Time Rebate ("PTR") program should be implemented in an effective manner as rapidly as possible. This program should be fully studied and evaluated for a minimum of two years.
2. If the Commission authorizes SDG&E to implement optional residential Critical Peak Pricing ("CPP") or Peak Shift at Home ("PSH") rates, the CPP or PSH rate should contain an event period adder of fifty cents per kWh.
3. SDG&E's proposal to reduce Peak Time Rebate ("PTR") credits should be adopted when the decision for this application becomes effective.
4. SDG&E should clearly display and describe its rates. If new PSH and Time-of-Use ("TOU") rates are authorized, SDG&E should show fully bundled rates for these optional rates on the PSH or TOU tariff book page to avoid customer confusion.
5. If the Commission authorizes SDG&E to implement an optional three-tier TOU or Time of Day ("TOD") rate, this TOD rate should be carefully monitored to ensure revenue neutrality. In its annual true-up filing, SDG&E should identify revenue shortfalls caused by customers transitioning from flat rates to TOU rates.

Table 2-1 shows DRA's proposed opt in PSH rates and SDG&E's proposed rates.

TABLE 2-1
DRA'S PROPOSED PSH RATES

	SDG&E Proposed PSH Rates (PSH adder = $0.91)	DRA Preferred PSH Rates (PSH adder = $0.50)	Difference
Summer On Peak			
Tier 1	0.12934	0.16522	0.03588
Tier 2	0.15011	0.18599	0.03588
Tier 3	0.27670	0.31258	0.03588
Summer Semi Peak			
Tier 1	0.11580	0.11878	0.00297
Tier 2	0.13657	0.13955	0.00297
Tier 3	0.26317	0.26614	0.00297
Summer Off Peak			
Tier 1	0.10004	0.10254	0.00251
Tier 2	0.12081	0.12331	0.00251
Tier 3	0.24740	0.24991	0.00251
Winter Semi Peak			
Tier 1	0.13656	0.13656	0.00000
Tier 2	0.15733	0.15733	0.00000
Tier 3	0.26070	0.26070	0.00000
Winter Off Peak			
Tier 1	0.13178	0.13178	0.00000
Tier 2	0.15255	0.15255	0.00000
Tier 3	0.25591	0.25591	0.00000

II. SDG&E'S PROPOSALS

SDG&E proposes to introduce voluntary residential CPP and TOU rates. SDG&E renamed its CPP Rate "Peakshift at Home" ("PSH"), and also re-named the

TOU rate a Time-of-Day ("TOD") rate. SDG&E's proposed PSH rate is composed of a PSH adder designed to collect generation capacity costs in excess to those recovered through the TOD rates. SDG&E's separate TOD rates collect generation capacity costs in on peak and partial peak TOD rates.

SDG&E states that it is making these proposals to follow guidance provided by the Commission for PG&E in D.08-07-045 and to prepare for default time-variant rates ("TVR") for residential customers in the future. SDG&E states that:

> "The decision did not require SDG&E or Southern California Edison Company (SCE) to adhere to the timetable or rate design guidance adopted in the PG&E decision but rather recommended that SDG&E and SCE take the decision into consideration when proposing rates for its customers. Subsequently, the Commission issued D.09-08-028 in SCE's 2009 GRC Phase 2 proceeding, directing SCE to follow the rate design guidance established in D.08-07-045. SCE is required to file dynamic pricing rates for its customers, including an optional CPP rate with a TOD rate design structure for residential customers, no later than September 1, 2010."(SDG&E Chapter 3, p.WGS-5)

Thus, PG&E and SCE have been directed by the Commission to file optional CPP rates for its residential customers, and SDG&E is doing the same at its own initiative.

SDG&E also proposes to reduce credits for its residential Peak Time Rebate ("PTR") Program in 2013, and briefly discusses future concerns about future default residential time-variant pricing rates.

III. DRA'S PROPOSED POLICY ON RESIDENTIAL TIME VARIANT - PRICING

The Commission, the Investor Owned Utilities ("IOU"s), and consumer groups have examined time-variant pricing issues in a number of proceedings and off-line discussions. DRA has given special attention to these issues for the residential and small commercial customers. DRA has consistently been concerned that making large and rapid changes to electric rates could have undesirable and unanticipated consequences for residential and small commercial customers. DRA is also concerned about the significant challenges of communicating with and explaining changes to such large numbers of these customers. Because of these challenges, DRA urges caution and moving slowly. DRA further recommends that parties continue to study and reevaluate policy and programs so that the best policy for residential customers can be formulated or designed. DRA fears that accelerating the transition to Time Variant Pricing ("TVP") will be counterproductive as it would not allow sufficient clear and effective communication with such a large numbers of customers regarding the changes to residential rate design. Implementing more gradual residential rate design changes will be easier for customers to understand. These new residential rate programs will not succeed without customer understanding and acceptance.

A. Peak Time Rate Program

The need to go slow, to educate customers, and to gain customer acceptance are key reasons that DRA supports the introduction of PTR programs. PTR has the potential to reduce peak demand substantially and to educate customers about the varying costs of electric capacity in different time periods.

SDG&E describes the PTR program:

> "The PTR program provides customers with a bill credit for each kWh of measured reduction in energy consumption during PTR events. Customers can only benefit under PTR since, unlike a PSH-type dynamic pricing rate, customers are not charged higher prices for energy consumed during PTR events but receive bill credits for reductions in energy consumption during these events (i.e., a "carrot only" type program)." (SDG&E testimony, p.WGS-20)

DRA agrees that the PTR program is a carrot only type of program, and that a program that offers positive incentives would be useful when ushering in change or educating residential customers about potential changes to residential rates. A customer would receive either a lower bill or no change in the bill; thus, this program would be expected to result in a high degree of customer satisfaction. In addition to educating customers and guarding against customer backlash, PTR has the potential for significant demand reductions because a high percentage of residential customers would participate[1],

[1] Customers who opt in to a CPP rate would not participate in PTR programs. DA and CCA customers would also not be eligible for PTR credits.

and thus even modest per customer reductions from such a large group of customers could result in substantial on-peak demand reduction. Customers would learn about varying costs of electricity via the PTR rebate which customers would receive for reducing usage during higher cost time periods. Receiving a rebate, or at least avoiding the higher bills that could result from higher time-variant pricing rates, would likely help to increase customer acceptance.

Critics of PTR programs have mainly cited the results of smaller pilot programs.[2] PTR has been tried in a limited number of places because it requires more sophisticated meters that are not yet widely used. The deployment of smart meters and PTR programs for SDG&E, SCE, and PG&E thus offers a great opportunity for California and the rest of the country to study larger, more complete PTR programs.

DRA thus proposes that SDG&E concentrate its resources on supporting its PTR program in order to help it succeed. DRA recommends allowing this program to operate for at least two years before major changes are made. This period will hopefully be sufficient for customers to understand, participate and benefit from this program. In the initial two years, SDG&E should actively study the program and the results of the program with the aim of answering these questions:

- How much peak demand reduction is achieved from this program?
- Does this program alone meet the Commission's demand response goals for residential customers?
- How many free riders are receiving credits without changing their electric consumption?
- Are the revenue shortfalls from free riders significant compared to the value of the demand reduction?
- What are the costs of the program, and how do these costs compare with the benefits achieved by the program?

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[2] There have been some programs such as the one at Baltimore Gas and Electric that has shown promising results.

Most importantly, SDG&E can analyze the customers' usage pattern and identify the customers that it can target for more aggressive time-varying rate option proposals in the future. DRA recommends implementing this program as quickly as possible and then evaluating how successful it is. After evaluating the program, changes can be considered.

DRA further recommends that the Commission take the experience of the PTR program, any voluntary residential CPP and TOU rates, and any small commercial time variant pricing rates into account before designing or proposing time variant pricing programs for residential customers.

IV. DISCUSSION

A. SDG&E's Proposed Residential PSH Rates

SDG&E proposes the introduction of a new voluntary residential PSH rate schedule with a PSH adder of 91 cents per kWh. This adder would be on top of new TOD rates.

In Chapter 5, DRA recommends the rejection of SDG&E's proposals to update its IT system for its CPP programs owing to SDG&E's deficient strategic IT plan and roadmap. SDG&E states that these system upgrades are needed for it to be able to implement voluntary PSH rates for residential customers. If this is true, and if DRA's proposal to deny approval of IT expenditures is adopted, then SDG&E will not be able to implement a voluntary PSH at this time. But, if SDG&E is actually able to implement a voluntary PSH rate with existing authorizations, or if SDG&E's revenue requirements proposals are adopted in part or in whole, then DRA has some recommendations concerning voluntary PSH rates.

If voluntary residential PSH rates can be implemented with the existing revenue requirement authorization, DRA proposes that the PSH rate adder be reduced to 50 cents per kWh. DRA makes this recommendation for the following reasons: 1) a very large adder of 91 cents per kWh could scare off customers signing up for this voluntary rate; 2) SDG&E overvalues generation capacity cost by not reducing it to reflect operational differences between a combustion turbine (“CT”) generator and the PSH rate; 3) PG&E’s currently adopted residential CPP rates have a 50 cent per kWh adder.

DRA believes it is preferable to begin a voluntary rate program with more moderate rates that will not frighten customers away. DRA believes a lower PSH rate would be more likely to attract new customers. The possibility of paying an additional 91 cents per kWh could easily be perceived as being too risky for many residential customers. A 50 cent per kWh PSH adder also would better reflect the operational differences between a CT and the PSH adder mentioned above. For example, to reflect these differences, SCE used a methodology in its AMI proceeding that reduces the value of the avoided capacity cost, used to calculate a CPP, by 46%. PG&E similarly reduced its avoided cost by 33% in calculating its PDP rates in its 2009 Rate Design Window.

SCE’s 46% reduction reflects the following differences between CPP and a CT:[3]

- A 0.49 factor based on relative normalized loss-of-load probabilities (“LOLPs”) to reflect the fact that a CPP event can only be called up to 18 days per year, whereas a CT can be called every hour of the year.
- A 0.95% factor to reflect the lower option value of CPP relative to a CT because the former can only be called 24 hours in advance, whereas the latter can be called almost instantaneously.
- A 1.15 factor to reflect the fact that that a demand-side resource (e.g., CPP) does not have to be covered by a reserve margin, whereas a supply-side resource (e.g., a CT) does.

These three factors are multiplied by each other, and the product is subtracted from 1.0. Applying these factors to the avoided cost adopted in SDG&E’s GRC settlement of $67 per kW-year would result in a PSH adder of 57 cents per kWh. DRA has rounded this down to 50 cents per kWh to be consistent with PG&E’s PDP adder. DRA’s proposal recovers the other 46% of the avoided capacity cost through the TOD energy rates.

[3] See A.07-07-026, Ex. SCE-4, App. B, pp. B-17 to B-20.

B. SDG&E's Proposal to Lower PTR Credits in 2013

SDG&E proposes to reduce its residential PTR credits in 2013. Rather than reducing the PTR credit in the middle of the program, DRA recommends that that SDG&E begin the program at the reduced credit level. The reduced PTR credit would better represent the value of capacity discussed above, which reflects the differences in the operating characteristics of PTR (or PSH) and a CT. It would also place PSH and PTR on the same costing basis. DRA proposes reevaluating and revising these PTR credits during SDG&E's upcoming GRC Phase II to reflect costing information representing SDG&E's generation system rather than SCE's.

SDG&E proposes to implement reduced PTR credits in 2013. This would result in starting the PTR program with relatively high PTR credits. The second year of the PTR would start with a dramatic drop in PTR credits that could confuse or disillusion residential customers. Customers might perceive that the PTR program was unstable or transitory, and thus might pay less attention to this program. It makes more sense to DRA to design a strong and stable PTR program that will inspire customer confidence and interest.

DRA supports SDG&E's proposal for lower PTR credits, but disagrees with SDG&E's proposal to change the credits midstream and its rationale for doing so. In its discussion of the PTR credit, SDG&E seems to assume that implementing, and guaranteeing the success of PSH rates, is the most important policy goal. Accordingly, the utility seems to believe that it would be acceptable to weaken its PTR program if doing so would help strengthen its CPP program. DRA believes that a good PTR program could provide demand response with the most customer satisfaction or lack of customer resistance.

DRA is optimistic that the PTR program could result in a significant amount of demand response. California will likely be the largest PTR roll out attempted in the United States, and it would be very useful to see what could be achieved from a complete PTR program covering a whole service territory.

C. SDG&E's Discussion of Future Default Time Variant Pricing Rates for Residential Customers

SDG&E also briefly discusses future issues relating to default time-variant pricing for residential customers. SDG&E states that it wants to keep its options open in the future for when the Commission starts to implement default time variant pricing for residential customers. SDG&E states:

> Defaulting residential customer to a PSH rate will be a big endeavor and thus, SDG&E believes it is important to leave open the possibility that residential customers should first be defaulted to a TOD rate before being defaulted to a PSH rate. (p.WGS-9, lines 15 to 17)

DRA agrees with SDG&E that the door should be left open regarding the rate option to which residential customers should be defaulted to if and when the Commission decides to implement default time-variant pricing for residential customers.

DRA recommends that the Commission examine the results of the PTR program, voluntary CPP and TOU rates for residential customers before designing future default time variant pricing program for residential customers. It should also study the results of time-variant pricing programs for small commercial customers since the majority of them are also unfamiliar with time variant pricing. Again, DRA urges caution and moving slowly with very clear communication. Moving to TVP rates will be a very large change for most residential customers, and the impacts of this change should be considered when designing a program. DRA thus agrees with SDG&E that the door should be left open to defaulting residential customers to a TOD rate in the future. Based on it's analysis performed thus far, DRA recommends that the Commission support TOD rates. However, this decision, including the more basic decision of whether the default rate even should be a time-varying rate, should be left to the future.

D. Rate Information for new Voluntary rates

If SDG&E implements new voluntary PSH and TOD rates, it is important that customers receive clear and complete information on these rates. SDG&E does not show complete bundled rates in its tariffs. SDG&E currently shows Utility Distribution Company ("UDC") rates, commodity rates, and DWR bond charge rates on separate tariff sheets. A customer searching SDG&E tariffs needs to know that these three rates need to be summed to obtain the full rate. SDG&E should be required to show fully bundled rates in its tariffs rather than requiring customers to add these three rate components together.

This recommendation is especially important for optional PSH and TOD rates. These rates already have the potential to confuse customers, and thus SDG&E should make the extra effort to ensure that customers receive clear information about rates they would pay. If customers do not understand the full bundled rates on these schedules, they could easily become upset and then opt out of these rates. Customer confusion resulting in the opting out of rates could harm the future success of time-varying pricing programs. There are no good reasons to continue to list rate components separately.

E. Time of Day Rates

SDG&E proposes offering new optional TOD rates with three rate tiers. SDG&E would display a single rate per TOD period on the tariff sheet, but would apply to that rate, tier 1 and tier 2 credits. SDG&E believes that not showing the tiers directly would be less confusing for customers. However, this proposal requires that customers make the necessary computations to know what they actually are paying. This may be more work than customers are willing to do. Thus, DRA also recommends that these rates be presented in a way that shows the final bundled rates the customers will pay. DRA also wants to monitor these rates to ensure that they are in fact revenue neutral. DRA thus recommends that SDG&E be required to identify revenue shortfalls caused by customers transferring from flat rates to TOD rates in SDG&E's annual true-up filing. With data on any shortfalls and further analysis, parties would be able to re-evaluate these new TOD rates and whether they are revenue neutral. If problems arise, these rates could be modified in the future.

V. CONCLUSION

DRA recommends that SDG&E's PTR program be implemented in an effective manner as rapidly as possible. Any reductions to PTR credits should be made when this application becomes effective. If SDG&E implements a residential CPP or PSH rate, DRA recommends that it contain an event period adder of fifty cents per kWh.

SDG&E should be required to clearly show fully bundled rates for new PSH and TOD rates on tariff sheets on its website to help reduce customer confusion. New residential TOD rates should be carefully monitored to ensure revenue neutrality.

CHAPTER 3

SMALL COMMERCIAL RATE DESIGN

CHERIE CHAN

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CHAPTER 3

SMALL COMMERCIAL RATE DESIGN

CHERIE CHAN

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Division of Ratepayer Advocates' ("DRA") testimony in response to San Diego Gas and Electric Company's ("SDG&E") Small Commercial Rate Design proposals in application ("A") A.10-07-009.

DRA recommends that the Commission:

1. Direct SDG&E to begin with a voluntary time-of-use ("TOU") rate with smaller TOU differentials designed specifically for small business customers.
2. Order SDG&E to more thoroughly investigate the effects of time-varying pricing on small commercial customers giving consideration to how customers will react to such pricing prior to rolling it out to all customers.
3. Address questions of operational readiness raised by DRA in Chapter 5 prior to any approval of SDG&E's dynamic pricing rates.

DRA represents the interests of residential and small commercial customers, characterized as non-agricultural non-residential or streetlight customers with maximum demands generally not exceeding 20kW[1]. The proposals in this proceeding would greatly impact SDG&E's 113,111[2] small commercial Schedule A customers.[3] This chapter addresses changes

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[1] D.09-07-045, Conclusion of Law No. 11.

[2] SDG&E Response to DRA Data Request #10, Question 4.

[3] Schedule A is SDG&E's "standard tariff for commercial customers with demand less than 20kW." SDG&E Schedule A: General Service Tariff page 1, filed August 20, 2010.

to SDG&E's commodity rates only, which are typically less than half the average small commercial bill.[4]

Table 3-1 below shows DRA's bundled small commercial rate design proposal in contrast to SDG&E's. Prices below are in cents per kWh, unless otherwise noted.

Table 1: Position Comparison Table

	SDG&E Proposal	DRA Opt-In	**DRA Default**
Summer			
On-Peak	21.9393	21.2743	**18.9633**
Off-Peak	16.9363	17.9503	
Winter			
On-Peak	15.8220	15.6320	**15.1580**
Off-Peak	14.3300	14.5670	
CPP	20		

II. SDG&E'S PROPOSAL

In this application, SDG&E proposes significant changes to its small commercial class rates. Currently, there are no TOU tariffs specifically designed for small commercial customers with demand under 20 kW[5].

Under SDG&E's proposals, customers will face a new default rate, called "Peak Shift at Work" (or "PSW"): PSW customers will be defaulted to a seasonally adjusted TOU rate with a Critical Peak Adder of 20 cents per kWh for seven hours called up to 18 times per year.

[4] In Chapter 2, DRA recommends that SDG&E be required to clearly display and describe its rates: DRA argues that SDG&E should be required to show fully bundled rates on SDG&E's website and tariff book pages to avoid customer confusion. DRA's recommendation extends to small commercial rates as well.

[5] SDG&E Rate AL-TOU "is optionally available to common use and metered non-residential customers whose Monthly Maximum Demand is less than 20 kW." (From Tariff Sheet Schedule AL-TOU, filed December 28, 2008). SDG&E also defines small commercial customers as generally being less than 20 kW (A.05-03-015, Exhibit 24, Chapter 5 MFG -15 at 6-8.) This schedule has a monthly basic service fee of $58.22 (at the secondary level) and a $7.39 summer on-peak demand charge, which are not appropriate for very small customers.

Even if the small business customer opts out of this TOU plus CPP rate, the customer could only opt out to a TOU schedule with one of the two adders: 1) a summer on-peak demand charge of $1.20 per kW, or 2) a capacity reservation charge. These alternative rate options are not likely to be any more acceptable or understandable by small commercial customers than is the PSW adder, because most small commercial and industrial customers have historically been on flat rates. The average small commercial customer likely does not understand the difference between a kWh and a kW, and is most unlikely to understand the concept of a capacity reservation charge as proposed by SDG&E as an alternative.

Proposed rates and their alternatives must be understandable to be effective in producing the Commission's desired behaviors: the new features proposed by SDG&E are overly complex and are not fundamentally simpler than the proposed default PSW rate with CPP layered on top of TOU.

A. SDG&E's Proposed Bill Protections offer No Meaningful Protection.

In its application, SDG&E proposes to offer twelve months of Bill Protection to any small non-residential customer that elects to remain on (i.e., does not opt-out of) PeakShift at Work."[6] Bill Protection provides customers who elect to remain on a PeakShift commodity rate the assurance that over the initial 12 month period, they will pay a commodity rate no more than their otherwise alternative commodity rate. In this

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[6] JSV-3

Shadow Bill process, CISCO[7] stores the customer's monthly bill for their Otherwise Applicable Rate."[8]

While the above bill protection proposal sounds consumer-friendly, further inspection shows otherwise. The proposed Otherwise Applicable Rate mentioned above is not the flat rate that the vast majority of small commercial customers are familiar with, or even a TOU rate that customers could more easily understand; instead, it will be the optional TOU schedule with a summer on-peak demand charge of $1.20 per kW, which continues to penalize customers who cannot shift their load. If the customer finds this rate to be unacceptable, the only other option to which he or she can opt out to is a CPP tariff with a large customer charge and a Capacity Reservation charge[9]. All of these options subject small businesses to undue risk, and are difficult for most small customers to understand.[10]

For bill protection to be meaningful, the customer should be protected by the rate it was on prior to the change (or something close to it). For most of these customers, this would be a flat rate, not the new complex rates with demand or capacity reservation charges SDG&E proposes.

Real, substantive bill protection must allow customers to return to the status quo or something close to it for a reasonable amount of time. For the overwhelming majority of these customers, this would mean bill protection based on flat rates, which DRA recommends here.[11]

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[7] CISCO is the Customer Information System in production at SDG&E. Testimony of SDG&E in this application, DJS-4

[8] DJS-4 15-16

[9] Testimony of SDG&E in A.10-07-009, page RWH-5.

[10] At a minimum, customers who are expected to pay demand charges or capacity reservation charges must understand the distinction between kW and kWh. Clearly, this will be a challenge for many small businesses.

[11] In DRA's testimony in A.09-02-022, DRA did not oppose PG&E's bill protection proposal, which provides protection from Peak Day Pricing to a relatively mild TOU rate

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B. Number of Events

There is considerable variation in the number of events proposed by each utility. SDG&E has proposed a range of up to 18 events per year, while Southern California Edison has proposed exactly 12 per year.[12] The parties in the Pacific Gas and Electric ("PG&E") Rate Design Window settled on a range of nine to 15 events per year.[13]

DRA recommends that a more narrow range similar to that settled on by the parties in the PG&E case be adopted by SDG&E. This will provide an additional measure of predictability for small commercial customers as well as provide the utility more manageable over and under-collections.

III. DRA'S PROPOSAL

As discussed in DRA Chapter 1: Dynamic Pricing General Policy, Chapter 5: IT Costs, Outreach and Education Costs, and later in this chapter, CPP is not appropriate as a default rate for Small C&I customers at this time. DRA thus proposes default flat, seasonally adjusted rates for SDG&E's small commercial customers with an optional TOU rate with smaller TOU differentials to promote adoption of these rates.

DRA does acknowledge the efforts SDG&E has made to mediate bill shocks to customers, such as lowering the CPP rates and TOU differentials from Marginal Costs as calculated by SDG&E, as well as their efforts to decrease customer confusion by removing the partial-peak rate.[14] DRA proposes to use SDG&E's marginal costs as a starting point,

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with a 20% differential. For the reasons described later in this chapter, DRA believes that the Commission should now act further to protect its smallest customers.

[12] Application of Southern California Edison Company to Implement New Dynamic Pricing Rates, dated September 1, 2010, page 8.

[13] Decision 10-02-032, Page 14.

proposing default seasonally-adjusted rates of 18.96 cents /kWh in the summer and 15.16 18.96 cents /kWh in the winter, derived from SDG&E's workpapers.

In its proposal, DRA uses SDG&E's marginal costs as a starting point and makes two adjustments to SDG&E's proposal in proposing its opt-in TOU rates.

1. CPP is Not Appropriate at this Time

For reasons described elsewhere in this chapter and in DRA's testimony, "complex rate designs should not be implemented before customers are shown to be ready."[15] Therefore, in calculating its proposed opt-in TOU rates, DRA reallocates the revenues to be collected from SDG&E's proposed twenty cent CPP surcharge to the On-Peak TOU Summer Period.[16]

2. On and Off-Peak Differentials

DRA commends SDG&E's efforts to mitigate potential bill shocks by flattening the differences between TOU periods. SDG&E included factor adjustments of 50% of the on-peak rate differential in the summer and 70% of the differential in the winter to help smooth out these drastic price differences.

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[14] RWH-10

[15] Petition For Modification of Decision 07-04-043 By Applicant San Diego Gas & Electric Company, Application of San Diego Gas & Electric Company for Adoption of an Advanced Metering Infrastructure Deployment, Application 05-03-015, September 9, 2010, page 4.

[16] DRA prefers that these revenues be allocated according to a Loss of Load factor or a similar methodology, which would also reallocate some of the CPP revenues to off-peak and winter periods as well; however, this information was not as readily available from the spreadsheets and would not result in too much of a substantive change in rates. DRA Data Request #12, question #9.

In this first exposure of most small commercial customers to time-varying rates, DRA encourages the CPUC to move further to protect our smallest commercial customers. Thus, in our proposal, DRA has moved the on-peak differentials to 25% in the summer and 50% in the winter. The resulting TOU differential of 3.3 cents per kWh between summer on and off-peak rates still provides some incentive to shift load without becoming unduly burdensome or intimidating as small commercial customers familiarize themselves with and attempt to adapt to time-variant electricity pricing.

3. A Time to Reconsider

DRA acknowledges that SDG&E's initial reliance on previous commission guidance such as PG&E's 2009 Rate Design Window Peak Day Pricing decision D.10-02-032 may have been a reasonable basis for exploring dynamic pricing at the time; however, new information continues to become available that tips the scales in weighing the appropriateness of SDG&E's CPP proposals.

Should SDG&E be able to offer additional, <u>optional</u> rate proposals such as an additional TOU rate with greater time-based price differentials, a semi-peak period, or voluntary CPP while incurring no or minimal additional costs to ratepayers, DRA would support implementing them, as described in chapter 5.

Due to the evidence presented by DRA in Chapter 1: Dynamic Pricing General Policy and Chapter 5: IT Costs, Outreach and Education Costs, and this chapter, DRA does not support any default or mandatory dynamic pricing for small commercial customers at this time. In the next section, DRA provides additional reasons why California should proceed cautiously before implementing potentially punitive default dynamic pricing policies, and start with mild TOU rates–with smaller on-peak to off-peak price differentials–instead.

IV. WHY TOU IS MORE APPROPRIATE THAN CPP AT THIS TIME

A. TOU is Easier to Understand

Most customers will have had some exposure to TOU rates in other areas of their lives. For example, most customers large and small have paid on- and off- peak rates through telephone bills for years. Motorists driving portions of highways 73, 161, and 241 within or near SDG&E's service territory pay different rates during on-peak, off-peak, and weekend periods[17]. Closer to home in the San Francisco Bay Area, drivers on the Bay Bridge also pay time-varying rates each rush-hour period, during other weekday hours, and on weekends.[18] Introducing a larger subset of customers to these predictable time-of-use rates without including unpredictable event-based surcharges will provide small businesses a less confusing introduction to electric time-varying rates.

In contrast to TOU, dynamic pricing of a delivered commodity will be completely new to small commercial customers. The difficulty in understanding CPP is borne out in SDG&E's testimony in this proceeding. SDG&E notes the need to hire contractors to conduct a massive face-to face campaign: "Transition costs will include a door-to-door campaign, planned for up 40% of the population, in order to provide customers with individualized help with their rate decisions."[19] This massive "Door to

[17] https://www.thetollroads.com/home/maps.htm

[18] http://goldengatebridge.org/tolls_traffic/toll_rates_carpools.php

[19] GCB -31, lines 1-3

Door Outreach Campaign" alone will cost $1,317,000,[20] and is but one example of the uphill road utilities face in introducing CPP to its smallest customers.

B. Predictable Prices May Lead to Structural Behavioral Changes

TOU rates may lead to more predictable reductions in peak usage every non-holiday weekday of the year, rather than on sporadic days that small commercial customers may or may not be aware of, due to Educational and Notification challenges, as described later in this chapter.

With predictable time-of-use rates, customers can use many of the technologies available today to programmatically shift their load. Programmable thermostats are now mandated for most new construction, and can be easily purchased for less than twenty dollars.[21] Modern dishwashers and clothes washers and dryers have a time delay to run during off-peak hours: these are all behaviors that TOU rates can help reinforce towards driving down peak demand.

With a predictable rate change of long duration, customers are more likely to make permanent changes, which could either be behavioral, or involve investments–however modest– in energy efficiency. In contrast, with short-duration, unpredictable event-based programs such as CPP, customers may adopt temporary behaviors such as simple avoidance, which will stop if the customer is uninformed, as soon as the event passes, or when the customer forgets or experiences fatigue.

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[20] Chapter 2 (Breed) Workpapers. Tab GCB-05., line 26

[21] Honeywell 5-2 Day Programmable Thermostat, $18.97 each, Home Depot Store #3555 Sports Arena Blvd San Diego, CA 92110 homedepot.com

C. More Data Will Help Parties Understand Potential Bill Impacts

In its testimony describing potential bill impacts to its customers, SDG&E provided one table of bill impacts, derived from a sample of 121 customers.[22] SDG&E is on the verge of acquiring data that will enable it to understand customer usage patterns better than it ever has before, as "SDG&E expects to deploy virtually all of its smart meters by yearend 2011."[23] SDG&E has an opportunity to review this incoming wealth of usage data from all 113,000 small commercial customers to better understand and target small commercial usage patterns, rather than relying on the limited sample of 121 customers. SDG&E should make use of this data or conduct TOU studies as described in Chapter 5 to obtain more knowledge of SDG&E small commercial customer use patterns before launching a default TOU or PSW program.

D. SDG&E's PSW Proposal Will Disproportionally Harm Small Customers

DRA analyzed SDG&E's limited bill impact data[24] and found that using SDG&E's numbers, the winners–those who are projected to receive a bill decrease–shown in hatched blue in the graph below, are generally larger users than the losers–those who would receive a bill increase–depicted in solid red below. Unfortunately, this discrepancy is not addressed in SDG&E's testimony.

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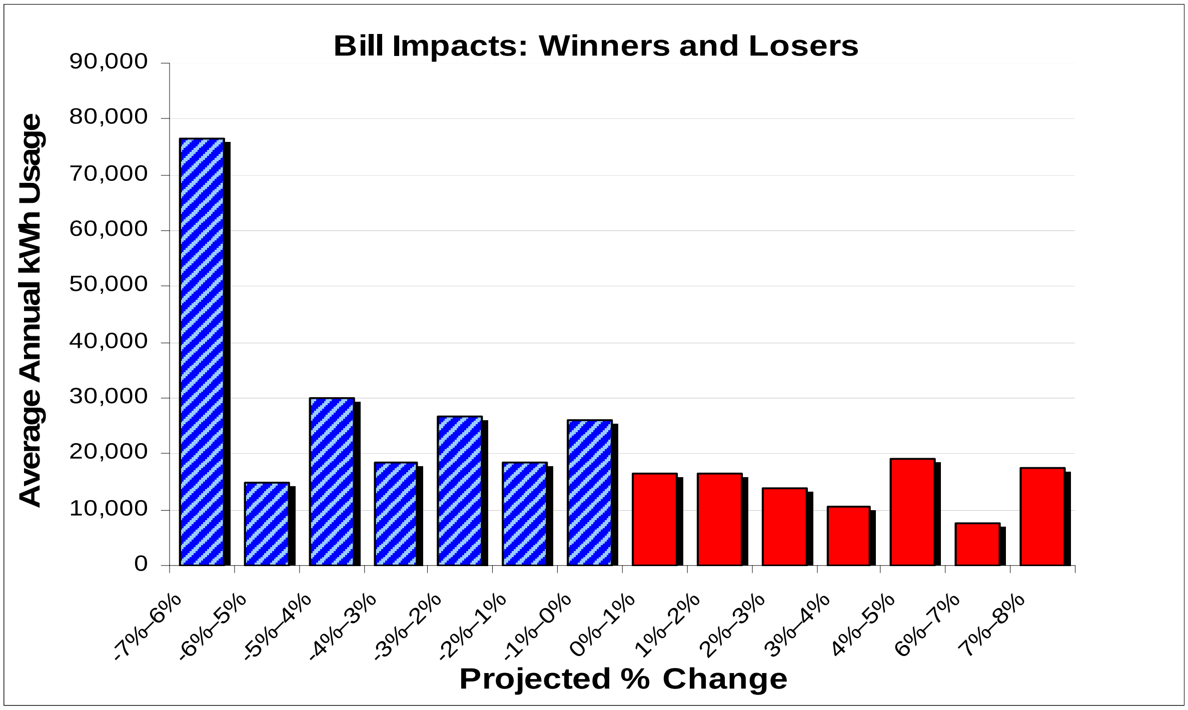
[22] "The bill frequency presented in Attachment RWH-9 was developed using data from an available sample of 121 customers." SDG&E Data Response #12 to DRA.

[23] Petition For Modification Of Decision 07-04-043 By Applicant San Diego Gas & Electric Company, Application of San Diego Gas & Electric Company for Adoption of an Advanced Metering Infrastructure Deployment, Application 05-03-015, September 9, 2010.

[24] Chp 4 (Hansen) Workpapers 7-22-10_Bill_Impacts.xls Tab: SDG&E RWH-9, With

(continued on next page)

Figure 1: Average Usage of Winners and Losers



E. SDG&E's Large Customer Reception to CPP is Lukewarm at Best

SDG&E's larger and medium-size commercial customers have the resources and knowledge to understand, elect, and respond to Critical Peak Pricing better than can small businesses. Yet, the data show that 39% of SDG&E's customers have opted out of CPP.[25]

Larger businesses generally have more employees, are more likely to have dedicated energy managers or consultants who understand electricity rate options monitoring their usage. Furthermore, larger businesses currently subject to CPP receive face-to-face interaction and billing analysis

(continued from previous page)

DRA Analysis

[25] DRA Data Request – DRA-05, SDG&E Response 4: November 23, 2010.

through assigned account representatives from SDG&E.[26] Once businesses are aware of a CPP event, it is more likely that somebody is available to change the energy usage on-premise.

DRA cautions that small businesses will likely have even more difficulty adapting to dynamic pricing than large ones, and will be less equipped to deal with the bill volatility associated with dynamic rates. The CPUC stated, in Rulemaking 10-05-005

> Small businesses are much like residential customers; they do not have the resources available to larger corporations nor the flexibility in accessing funds that bigger businesses have. This is a crucial time for policy makers to ensure that our small businesses stay afloat.[27]

F. Recent Lessons from PG&E

On January 14th, 2011, PG&E filed a Petition for Modification ("PFM") of D.10-02-032, specifically seeking to roll out TOU to small commercial (and medium) commercial customers first prior to CPP instead of having small customers face both at the same time. PG&E cited four lessons learned in its implementation of default CPP. Lessons number two and three, noted on pages 12 – 16 of the PFM, are of particular relevance to SDG&E in that they describe customer behavior in general. SDG&E should consider this new information in reconfiguring their PSW plans.

> Lesson Two: For mass market customers not currently on any form of time-varying rates, allocating time to carefully

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[26] Bode, Josh and Mangasarian, Pail, Freeman, Sullivan & Co. Prepared for: Kathryn Smith, Electric Load Analysis, San Diego Gas & Electric. "SDG&E Non-Residential Default Critical Peak Pricing Analysis of Enrollment Choices." August 18, 2010, page 23.

[27] Commissioner John A. Bohn, CPUC Press Release. San Francisco, Oct. 28, 2010. CPUC Revises Small Business Billing And Deposit Rules

> convey the additional context for the purpose and benefits of those rates is critical to ensure initial acceptance of a default program and its successful adoption[28]

The "mass market customers not currently on any form of time-varying rates" adequately describes nearly all of SDG&E's small commercial customers. SDG&E doesn't currently have any available TOU rates specifically designed for small commercial customers: the only TOU rate that small customers with monthly maximum demand less than 20kW can elect requires a customer charge of $58.22, and a demand charge which would render this rate not cost-effective for most small customers.[29]

TOU alone will already be a large change for the vast majority of small commercial customers. In support of this statement, PG&E conducted a focus group in July, 2010 cited in the PFM: PG&E noted that "because peak times were during business hours, they [small business customers] would not be able to adequately shift enough load to benefit from the new rates." More time is needed to help customers understand the new rates and address customer resistance to time-varying rates.

> Lesson Three: PDP[30] is a complicated rate, even for the most knowledgeable customers. In order to ensure acceptance and success, it needs to be fully explained and rolled out separately after TOU.

With large customers unable to understand PDP without significant personal intervention from account executives, it is unclear how smaller customers who will not receive such assistance will fare any better. DRA

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[28] Petition of Pacific Gas And Electric Company For Modification Of Decision 10-02-032. January 14th, 2011, page 12.

[29] SDG&E Tariff Schedule AL-TOU page 1, filed March 28, 2008.

[30] PDP represents PG&E's Peak Day Pricing Proposal, which like SDG&E's PSW and Peak Shift at Home proposals in its application, have event-based dynamic pricing components.

strongly encourages SDG&E to learn from PG&E's findings and recommendation that TOU should be slowly implemented first, with the caveat that dynamic pricing should only be proposed once customers and utilities have gained an adequate understanding of dynamic pricing for its smallest customers.

G. Small Commercial Customers Face Barriers to Investing in Energy Management Equipment

With economic barriers to investment such as low property ownership rates and economic uncertainty, small commercial ratepayers are less incentivized to invest in upgrades to respond to an unknown number of events. Small energy users are probably more likely than large energy users to rent space in a building, rather than own their respective place of business. Furthermore, according to SDG&E, turnover in small commercial accounts runs as much as 10% --15% annually.[31] With such high turnover and low ownership rates, consumers are less likely to or be able to invest the time and capital needed to purchase and install energy management equipment or invest in energy efficiency upgrades such as improved air conditioning systems.

H. Educational and Notification Challenges

SDG&E acknowledges that "Preparing the small nonresidential market for PSW represents a significant education challenge"[32] SDG&E further elaborates that "to make a fully informed decision, and to successfully manage their costs under the new rates, there are a substantial number of new behaviors that the customer will be encouraged to adopt. These are:

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[31] GCB—38, lines 7.

[32] GCB-7, lines 2—3.

- Studying the information resources and tutorials available online;
- Enrolling in My Account and access the PSW tools;
- Using the online presentment toll and study their energy usage profile;
- Running the rate comparison tool under different scenarios and rate options
- Proactively selecting PSW as their preferred rate via the online enrollment form, or alternatively, select one of the other rate options;
- Providing SDG&E with their contact information so they can be notified on ReduceYourUse Days and also receive information about energy reducing solutions;
- Developing a personal demand reduction strategy for ReduceYourUseDays; and
- Implementing a strategy on ReduceYourUse Days."[33]

Of these eight encouraged—and possibly necessary—behaviors SDG&E encourages for successful cost management, five require internet tools, one requires that SDG&E have updated customer contact information, and the remaining two behaviors are dependent on the analysis of information resulting from the first six behaviors. DRA will address these three behavior-types separately.

1. Behaviors 1–5: SDG&E Relies Heavily on the Internet, to which Small Business Lacks Access

Of the eight behaviors SDG&E encourages the consumer to adopt as mentioned above, the first five involve logging into the internet. Yet, according to SDG&E's own notes of a meeting it held with the California Small Business Association prior to this filing, "70% of small bus [sic] does not have the internet at work, computers yes, internet no."[34] SDG&E

[33] GCB, pages 7—8.

DRA Data Request 10, question 1 Response. Internal email from Glen Breed titled CPP-S: Calif. Small Bus Assn – Meeting Notes 2/17/2010 further captured a quote from one of the invited participants to this meeting to one of SDG&E's witnesses in this proceeding: "no one will ever look at your website Glen, no matter what you do"[35] Despite the clear message from the small business community that the internet is not an appropriate medium for educating and communicating with small businesses, SDG&E's proposals disproportionately lean on a tool inaccessible to the majority of small business while they are on the premises.

While some small business owners and managers may have access to the internet at home or at a public library, DRA questions whether they want to or will be able to spend their precious leisure time after work hours doing this required homework, especially when the energy-consuming equipment at their small business is somewhere else other than where they have internet access. Many of these customers cannot simply leave work early to do this work at home because they have to be at work during business hours. Many of these businesses also do not have enough employees to send one of them home to do this homework. Even SDG&E's largest companies with dedicated in-house energy managers were not able to do the necessary analysis without much help from SG&E's account executives.

2. Behavior 6: Maintaining Small Business Contact Information is notoriously difficult.

Utilities have faced an ongoing challenge of contacting their commercial customers given frequent changes in ownership, management, or staffing. In addition, changes in phone numbers or email addresses occur even more often than changes to physical addresses. To that end,

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[35] DRA Data Request 10, Question 1 Response. Internal email from Glen Breed titled "CPP-S: Calif. Small Bus Assn – Meeting Notes 2/17/2010"

SDG&E has stated that it faces extreme difficulties in maintaining a database of contact information for its customers:

> "Staffing for this function must address a significant amount of exception handling, including but not limited to large volumes of return mail from both traditional mail and email. Some of the return mail is due to the normal cycle of turnover in small accounts, which runs as much as 10%--15% annually."

PG&E has also had similar problems maintaining email and telephone contact information for customers, which has affected the success of PG&E's CPP programs.

> Customers' failure to update contact information has been a challenge with customers on SmartRate™. Based on 2009 SmartDay Event Notification Results Summary (see Attachment 1) PG&E has had approximately **31 percent undeliverable** notification phone calls and 16 percent undeliverable emails for individual event notifications. Additionally, the customers may provide incorrect contact information, requiring additional manual work from PG&E.[36]

Clearly it is very difficult to notify customers of event days when adequate contact information does not exist.

3. Behaviors 7–8: Developing and Implementing Strategies

Behaviors seven and eight are merely strategies the customers must develop and implement with the information they have presumably gleaned from the previous six steps described above. Given the limited access small business consumers have to the internet as well as difficulties the

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[36] A.09-02-022, PG&E Rebuttal Testimony, Chapter 6, page 6-2. Also see attachment to Chapter 6 for data on number of customers not properly notified of critical peak events owing to incorrect contact information. Emphasis added.

California utilities face in maintaining contact information for small customers; we suggest that these recommended behaviors for event-based pricing adoption and success as described by SDG&E will be unduly difficult to implement.

I. Dynamic Pricing Produces Limited Gains

In a paper written by one of the leading advocates of dynamic pricing, Severin Borenstein cautions that the utility cost savings from dynamic pricing may not be as great as one would expect. As Dr. Borenstein writes,

> as exciting as the prospect of "getting prices right" may be to economists, the potential gains were likely to be only 5 percent or less of the energy bill . . . The reason for this is worth highlighting: in an electric system that must always stand ready to meet all demand at the retail price, the cost of a constant-price structure is the need to hold substantial capacity that is hardly ever used. But utilities optimize by building "peaker plants" for this purpose, capacity that has low capital cost and high operating cost. The social cost of holding idle capacity of this form turns out to be not as great as one might think.[37]

Given the somewhat disappointing benefits of dynamic pricing shown above, DRA questions whether the expense, disruption to customers, and bill unpredictability is worth the meager potential gains. In addition, as described in detail DRA's policy chapter, Resource Adequacy measures have decreased price fluctuations on the wholesale market.

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[37] Borenstein, S. NBER Reporter: Research Summary 2009 Number 1 Electricity Pricing That Reflects Its Real-Time Cost

J. TOU May Produce More Greenhouse Gas Reductions Than Does CPP

The Commission's Energy Action Plan II states that the impacts of climate change should drive Commission energy policy:

> Climate change is the most serious threat to our environmental future, and demands immediate action. Its symptoms are already evident in California. ….Increasing energy efficiency, demand response, and renewable resources to the maximum extent possible in California and the western region will … reduce our contribution to climate change.

New research shows that TOU may produce greenhouse gas reductions comparable to or better than CPP.[38] While SDG&E's proposed PSW events can be called up to 18 times per year with as little as one day of notice, predictable year-round TOU price differentials should lead to permanent behavioral changes that can reduce greenhouse gas emissions derived from on-peak generation even more.

V. CONCLUSION

DRA recommends that the Commission reject SDG&E's PSW proposal based on the:

- lack of substantive bill protections for SDG&E's smallest commercial customers,
- problems PG&E has faced implementing dynamic event-based pricing to its smallest commercial customers,
- difficulties small customers face in this economy,
- obstacles SDG&E's smallest businesses would face understanding, being aware of, and acting upon dynamic pricing events, and
- evidence provided by DRA in its testimony.

[38] Electric Rate Design and Greenhouse-Gas Emissions Reduction. Proceedings Of The IEEE Power And Energy Society, 2009, Calgary Abs. Blumsack.

SDG&E's PSW proposal would subject California's most vulnerable businesses to volatile time-based energy charges with unpredictable and often unavoidable high-priced events. DRA recommends that small commercial customers be protected from price volatility, studied, and gradually transitioned to time-based TOU rates that are easier to understand and act upon.

CHAPTER 4

ANALYSIS OF PROJECT BENEFITS

LOUIS IRWIN

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CHAPTER 4

ANALYSIS OF PROJECT BENEFITS

(Witness - Louis Irwin)

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Division of Ratepayer Advocates' ("DRA") calculation of the incremental benefits of San Diego Gas and Electric Company's ("SDG&E") proposal to implement dynamic rates. SDG&E has proposed new Peak Shift at Home ("PSH") and Peak Shift at Work ("PSW") programs for residential and Small commercial and industrial ("C&I") respectively. It also discusses modifications to its Peak-Time Rebate ("PTR") program.

DRA estimates that the benefits of SDG&E's new rate programs are $43.7 million less than those assumed in SDG&E's Advanced Metering Infrastructure ("AMI") business case. Yet SDG&E's funding request in this case is $118.1 million.[1] There are two differences between the assumptions supporting the demand response benefits in this chapter and those in the AMI proceeding:

- The PTR and PSW event hours for this case are less, and
- The proposed PTR credits and PSW adders are lower.

DRA used participation rates that are generally higher than those used in the AMI proceeding based on SDG&E's response to DRA Data Request #8. Recent experience with opt-out and adoption rates, however, may suggest that these participation rates are overly optimistic.

DRA set its PTR credit and PSW adder to reflect what it believes is the true cost basis, as described in Chapter 2 herein. In fact, in its final results, it doubled SDG&E's PSW $0.20/kWh adder to get closer to a true cost basis. DRA perhaps could have gotten closer to the AMI results by increasing the number of event hours. However, DRA warns that one cannot merely increase the event hours to

[1] A.10.07.009, Chapter 1, p. JSV-15, July 6, 2010,

equal those found in the AMI business case without also reducing the PTR credit and PSW adder (all other variables being held equal). This is because these credits and adders are a function of the number of hours to which they apply.

These results call into question whether the AMI proceeding, in retrospect, overestimated the DR benefits. Before spending another $118.1 million, this issue must be investigated. DRA does feel uncomfortable spending $118.1 million to produce benefits that the AMI proceeding itself only estimated to be, at best, on the order of $50 million. In chapter 5, on Information Technology, Outreach, and Education Costs, DRA recommends that the Commission dismiss SDG&E's dynamic pricing proposal, as SDG&E has not performed adequate analysis and research to ensure that investments will be cost effective. DRA's analysis and calculation of incremental benefits in this chapter casts additional doubts on the value of SDG&E's dynamic pricing proposals. The Commission needs to ensure that expenditures of such large amounts, amounting to 21% of what was authorized for AMI, will result in commensurate benefits for ratepayers.

Accordingly, DRA recommends that:

1. The $43.7 million decrease in benefits associated with this proposal is considered by the Commission in determining whether to grant or deny SDG&E's funding request.

2. Future rate proposals involving substantial implementation costs should be accompanied by a detailed cost / benefit analysis that also include alternatives to dynamic pricing such as enhancing funding for non-rate strategies such as energy efficiency or other demand response programs.

II. BACKGROUND

DRA used, as a starting point for its calculations, the demand response ("DR") benefits that SDG&E had used, in part, to justify its AMI deployment at a cost of $652 million.[2] In its initial AMI application, SDG&E's assumed DR

[2] A05-03-015, D.07.04.043, April 12, 2007, p. 1, and in the Attached Settlement Agreement indicated that the Commission authorized SDG&E $572 million for its AMI for years 2007 through 2011. In the same decision at p.85, it indicates that whole project cost is $652 million.

benefits of $137.4 million for its residential and small C&I rate classes.[3] They came from establishing a Peak Time Rebate (PTR) program for residential and Small C&I customers, as well as default TOU and voluntary Critical Peak Pricing ("CPP") for all Small C&I customers.[4]

The post-settlement Commission Decision reduced the residential DR benefits relative to those in SDG&E's original application. The residential gross benefits were reduced from $123.2 million to $37 million based on three changes:

- A decreased expected awareness / effective participation rate (50% instead of 70%),
- A shorter time horizon (17 years instead of 34 years), and
- A lower avoided capacity value ($52 kW- year instead of $85 kW – year).[5]

The post-settlement Commission decision leaves intact the SDG&E proposed gross benefits for the Small C&I customers at $14.2 million. The decision should have reduced the Small C&I benefits to reflect the fact that it adopted a lower avoided capacity cost ($52 per KW-year) and a reduced time horizon (17-year) for the *entire* application.[6] Thus, for its calculations herein, DRA uses as a starting point its own estimate of Small C&I DR benefits of $6.7 million as filed in testimony.[7] This estimate is based on the reduced time horizon and avoided capacity values that the Commission Decision adopts. Using this revised benefit estimate, the AMI total gross DR benefits over the two rate classes is $43.7 million ($37 million + $6.7 million).

[3] A05-03-015 Ch. 6, Demand Response Benefits, July 14, 2006, Table SSG 6-3, p. SG-11.

[4] A05-03-15, Ch. 2 AMI Business Vision, Policy and Methodology, July 14, 2006, Figure EF-1, p. EF-3.

[5] D.07.04.043, April 12, 2007, p. 54. The "effective participation rate" subtracts out customers who are signed up automatically for a rate, but are unaware of this fact and therefore, do no consciously participate.

[6] D.07.04.043 April 12, 2007, p. 90, 92.

[7] DRA AMI. A.05.03.015, Chapter 5, Rate Design, Participation Estimates, and Avoided Demand Response Program Costs, Table 5-2, p. 5-18, August 14, 2006.

Making SDG&E's AMI business case cost effective was not easy. Both SDG&E and the Commission had to work through several rounds of proposals to achieve a final business case that could even achieve positive net benefits. The post-Settlement Decision defines a range of net benefits (i.e., total benefits minus total costs) for the total AMI project of $40 million to $59 million.[8] But to achieve these net benefits, the Commission needed to include a wider array of environmental and societal benefits than had originally been assumed.[9]

III. BENEFIT ANALYSIS OF SDG&E'S 2010 DYNAMIC PRICING PROPOSAL

A. Introduction

The SDG&E dynamic pricing testimony does not perform the essential task of presenting a cost / benefit ("C/B") analysis to justify its cost request. It appears that SDG&E saw this as unnecessary since it believed it was merely complying with the Commission directives from D.08-07-045. However, a mandate to perform is never a license to be inefficient or bypass review on the presumption that efficiency is being achieved. While the scoping memo did not require SDG&E to perform a C/B analysis, it made it clear that such a review was within the scope of this proceeding.[10]

This analysis will focus first on the demand response ("DR") benefits. Secondly, it considers environmental benefits and avoided DR program costs that result from customer load reduction and load shifting. For Peakshift at Home ("PSH"), a complete and rigorous calculation of the incremental DR demand response benefits would include all the inputs shown in Table 4-1. The table summarizes inputs from the AMI proceeding, which DRA was able to assemble, and the comparable values from SDG&E's current dynamic pricing proposals.

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[8] D.07.04.043, April 12, 2007, p. 93.

[9] D.07-04-043, pp. 70-74.

[10] A.10.07.009, Scoping Memo and Ruling, September 30, 2010, p. 6).

As can be seen, a number of the inputs are identical and thus would produce no incremental benefits. Since SDG&E also proposes changes to the existing residential Peak Time Rebate ("PTR") program, these changes are included in Table 4-1 as well. For Peakshift at Work ("PSW") the changes from the AMI inputs are even fewer.

DRA does not attempt a replication of the Commission Decision findings of DR benefits using all the inputs referenced in Table 4-1. This "from the bottom up" calculation is complex and involves multiple factors. The increased accuracy relative to the simpler analysis that DRA performed would not have changed DRA's overall conclusions. DRA's simpler approach uses the Commission authorized AMI residential DR benefits ($37 million) and the DRA proposed Small C&I DR benefits ($6.7 million) as starting points. For residential PTR, these figures then are subjected to a "top down adjustment" that only reflects how the assumptions for the current Dynamic Pricing proposal (last column of Table 4-1) differs from those used in the AMI business case (middle column of Table 4-1). DRA followed a similar approach for non-residential PSW. These adjustments are described in Section III.D below for residential customers and Section III.E for Small C&I customers.

Table 4-1

Inputs for Residential Demand Response Benefit Calculation

	AMI Rate	2010 Dynamic Pricing PSH Rate
Energy Usage For CPP Hours / Month	14.1 kWh / month for CPP hours usage.	Assumed the same hourly usage as AMI
Expected CPP hours per year	91 hours = 13 event days x 7 hours per event day	63 hours = 9 event days (on average) x 7 hours per event day
Price Elasticity of Demand for CPP Hours	-.11	Presumed the same.
CPP Price Incentives	$0.65 over a base price of $0.149	$0.91 over a base price of $0.186 $0.50 for those customers remaining on PTR (without enabling technology)
Value of Avoided Capacity	$52 kW-year	$67 kW-year.
Awareness / Effective Participation Rates	50% PTR	6% PSH 50% PTR
Other Factors: Inputs influencing usage (e.g. weather, technology), customer growth and meter deployment rates, reserve margins, line loss factors and discount rates for present value of benefits	Unspecified in Decision	Presumed the same.

B. Overview of the Main Input Variables

Before discussing how DRA performed its “top-down adjustments” to the starting figures of $37 million and $6.7 million for residential and small business customers respectively, it will first discuss how the various inputs changed between the two cases.

Usage During Event Hours. DRA calculated estimates of the energy usage during PTR events for the AMI proceeding by using a weighted average of coastal and mountain usage (11.4 kWh / month) versus the desert and inland (17.9 kWh) usage for peak hours on a CPP day. Weighting the two usage values, by the relative number of customer in each of these regions,[11] results in an estimate of 14.1 kWh / month. There is no reason to expect significant changes in usage patterns from one proceeding to the next. Thus, the usage per hour in each event hour is assumed to be the same between the two proceedings. The number of event hours, however, is different, as discussed below.

Expected CPP Hours Per Year. The number of PSH event days can vary from 0 to 18, but the costs are modeled on an average expectation of 9 event days per year.[12] Therefore, the Dynamic Pricing PSH is based on fewer expected events per year (9 versus 13) than AMI, but on the same designated peak period (7 hours).[13] Therefore, the AMI PTR schedule calls for 91 event hours per season (13 events x 7 peak hours), whereas PSH calls for 63 hours (9 events x 7 peak hours). The net effect is a 31% reduction in the number of event hours.

Price Elasticity of Demand. Both DRA and SDG&E agree that there is no reason to presume a difference in consumer behavior (price elasticity) between the two proceedings.[14] There is also precedent for using the same elasticity for

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[11] AMI A05-03-015, Ch 16, July 14, 2006, Table SSG 6-6, p.SG-15. Customer counts, used for weightings, are current data from William Saxe, February 16, 2011. About 58% of the customers were in the coastal and mountain region and 42% were in the desert and inland region.

[12] A.10-07-09 Ch 3, July 6, 2010, p. WGS-16.

[13] A.05-03-015, Chapter 6, July 14, 2006, pp. SG-6, SG-7, A.10-07-009, Chapter 3, Table WGS-6 and lines 15 – 19, p. WGS-16.

[14] DR DRA-08 Response to Question 2C, p. 9.

different rate designs. For instance, SDG&E, for its AMI PTR proposal, used a price elasticity that was estimated for CPP.[15]

The elasticity estimate in the table is an average for coastal and mountain regions versus desert and inland, for CPP hours without enabling technology. The enabling technology is used by a much smaller subpopulation with stronger price sensitivity. Different elasticity values are recorded under other conditions (e.g., non-CPP hours).[16]

Price incentives. There are some changes in the price incentives offered by PTR in the two cases. In the original AMI case, the proposed PTR credit was $0.65 over a base price of $0.149.[17] The PTR credit for residential customers was increased to $0.75 (without technology) and $1.25 (with technology) in the last general rate case.[18] DRA uses the original SDG&E AMI proposal ($0.65 adder over a $0.149 base rate) in its calculation of incremental benefits below since the demand response benefits from AMI presumably are based on this. SDG&E proposes, in this case, to decrease the PTR credits from $0.75 to $0.50 (without enabling technology) in the second year of the program.

A voluntary PSH rate was not assumed to be available in the AMI proceeding. SDG&E currently proposes a PSH surcharge of $0.91 over an average residential rate of price of $0.186.[19]

Avoided Capacity. The current Dynamic Pricing proceeding uses $67 / kW-year for marginal generation capacity costs.[20] This figure is 29% higher than the $52/kW-year value approved in the AMI Settlement Decision.[21] DRA's

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15 Estimated for the California Statewide Pricing Pilot ("SPP").

16 AMI A05-03-015, Ch 13, Appendix C, March 30, 2005, Table C-7, p.9.

17 A.05-03-015, AMI Testimony, Ch 6, March 28, 2006, p. SSG-4 & SSG-26.

18 A10-07-009, Ch 3, p. WGS-13.

19 DRA Workpapers.

20 A.10-07-009 Ch 4, July 6, 2010, p. RWH-5.

21 D.07-04-043, April 12, 2007, p. 64.

analysis back-adjusts the AMI DR benefits to place both proceedings on the same avoided capacity cost.

Awareness / Effective Participation Rate. While the AMI proposal defaulted all residential customers to the PTR program, only customers who are aware of the program are assumed to respond. Thus the awareness rate can be considered the *effective* participation rate. The AMI decision reduced the awareness rate of customers from 70% in the original business case to 50%.[22] SDG&E claims that, while 50% of the customers will participate in (or be aware of) PTR, only 4% to 8% of all accounts will sign up for the new PSH rate.[23] The latter translates to an average participation of 6%.

SDG&E, however, did not make explicit whether these PSH converts were previously "aware" or "unaware" PTR customers. If they were already aware (quite plausible), then the active participant total will not increase, for every PSH participant previously was a PTR participant. It is possible, however, that the new SDG&E outreach efforts will create "newly aware" customers. In this case, the 6% PSH participation rate would be in addition to the 50% active participation rate for PTR customers. DRA assumes that the 6% are all new recruits (from the unaware pool). This assumption is most favorable to SDG&E's 2010 Dynamic Pricing proposal.

C. Basics of the Demand Response Benefit Calculation

In its most basic form, the calculation of the DR benefits is not complicated. The following formulas are simplifications of that actually used in SDG&E's AMI testimony. The process involves first calculating the kWh impact and then monetizing the value:[24]

[22] D.07-04-043, April 16, 2007, p. 53.

[23] DR DRA-008, Question 2c. p. 8.

[24] A.05-03-015, Chapter 6, July 14, 2006, p. SG-5.

1) **kWh Impact** = (Average use per customer during the critical peak hours by rate class) x (The percentage change in CPP period use given a change in price) x (The number of customers in the rate class) x (The Participation Rate)

2) **Total Benefits =** (kWh Impact) x (Avoided Capacity Cost) + (kWh Impact) x (Avoided Energy Cost)

The above formulas do not provide the details of how to apply an avoided capacity cost or how to calculate the "percentage change in peak period use". Furthermore, when making a thorough calculation of DR benefits, from the bottom up, inputs should be estimated on an annual basis and discounted to obtain a net present value. The customer counts, participations rates, energy use, base rates, and other inputs all change from year to year.

Though the above formulas are illustrative, they do serve as a useful guide of how benefits will change when one variable, such as the participation rate or event hours, is altered. DRA's simplified "top down" approach for estimating these benefit changes is described in the next section. It involves making proportional changes to the starting values of DR benefits. Though DRA's approach has less formulaic and theoretical backing, it has the several counterbalancing strengths: 1) ease of calculation and 2) assurances that the resulting benefit proposals are properly scaled to the Commission Decision. The analysis is performed individually for each paired rate plan and class, starting with PSH and the residential rate class, followed by Small C&I and finally Medium and Large C&I.

D. Residential DR Benefit Changes for the PSH, PTR and TOU Rates

The first adjustment that DRA makes, before making adjustments for the individual rate plans, is to update the AMI demand response benefits for a higher capacity cost. As noted in Table 4-1, the current Dynamic Pricing proceeding adopts a value of $67 per kW-year, which is a 29% increase over the Settlement Decision value of $52 per kW-year. Updating the AMI DR benefits results in an increase in the residential DR benefits from $37.0 million to $47.7 million, and an increase in the Small C&I DR benefits from $6.7 million to $8.6 million. This produces a total of $56.3 million in benefits for the two rate classes.

DRA also considered a variety of other price index adjustments that it could have made. However, the time between the 2006 AMI Decision and the current Dynamic Pricing proceeding has been marked by recession and nearly flat price indices. Therefore, DRA proposes no other price adjustments other than the one made for avoided capacity cost.

1. PSH Rates

PSH is a new program that increases price incentives relative to those in the AMI business case. While this leads to some increased benefits, SDG&E also proposes reducing the incentives for the residential PTR rate. Since the existing PTR rate has at least eight times the participants that are predicted for PSH, the net effect will be a decrease in benefits for the residential rate class. Thus, DRA projects a $4.4 million increase associated with PSH, but a $27.4 million decrease associated with residential PTR. This creates a net decrease for PTR and PSH together of $23.0 million. Details of the calculations follow.

DRA estimates the incremental PSH benefit by starting with the PTR benefit that was calculated in the AMI proceeding. It first converts the $47.7 million benefit from residential PTR to a per customer estimate. DRA then multiplies this by the number of new PSH customers to arrive at an initial PSH benefit value:

1. **Benefits per Customer**: $76.28 over the 17-year span

   $76.28 = ($47.7 million in total proposal benefits) / (1.25 million customers x 50% participation rate).[25]

2. **Total expected new participants**: 75,000

   75,000 = (6% increased participation) x 1.25 million residential customers).

[25] DR DRA-008, Question 2c. p. 8.

3. **Total New DR Benefits**: $5.7 million

$5.7 million = $76.28 per customer x 75,000 new customers.

After this initial PSH benefit estimate is created, DRA uses an iterative process to adjust the estimate for two substantial factors where the value for PSH is different from the PTR value in the AMI case. These are the number of events and the PSH price incentive. The computation process and results are described below:

1. **Event Hours**. As noted in Table 4-1, the Dynamic Pricing will have 31% less critical event hours per year. Scaling the DR benefits down accordingly, the result is $3.9 million (= 0.69 x $5.7 million).
2. **PSH Price Incentives.** The second adjustment is to account for the differing price incentives between the two proposals. The PSH has a higher incentive ($0.91) than the original AMI incentive of $0.65. The base price is also higher for the current proceeding ($0.186 versus $.149 for AMI). Although it is a bit more involved, one can still make a reasonable approximation by making a proportional adjustment to the existing benefits using these price ratios.[26] The ratio of the new incentive over the new base price compared to the AMI incentive to AMI base price is 1.12 (a 12% increase)[27]. Incorporating this factor increases the residential DR benefits to $4.4 million (= 1.12 x $3.9 million), which is a $0.5 million increase. This benefit is quite sensitive to the incentive price.

2. TOU Rates

PSH also includes a TOU component. DRA, however, did not calculate an increase in benefits associated with the TOU component. It did not do so because the TOU commodity rates shown in Attachment RWH-3 of Chapter 4 of SDG&E’s testimony appear to be lower than the commodity rate applicable to the default residential schedule in the summer season. Had DRA included this effect, it would have resulted in a reduction of benefits.

[26] DRA Workpapers.

[27] 1.12 = ($0.91 / $0.186) / ($0.65 / $0.149)

SDG&E has also proposes to phase out two existing residential TOU schedules. Namely, SDG&E proposes to phase out its existing TOU schedules (DR-TOU and DR-TOU-DER) on the basis that they are complicated (4 tiers and 2 time periods).[28] DRA did not calculate the associated reduction in benefits because a fair portion of customers on these schedules presumably would transfer to PSH or one of the new TOD rate options. But customer counts remain unestimated. Therefore, the net TOU effect remains unknown. It is most likely, a relatively smaller impact.

3. Incentive Changes to the Residential PTR Rate

The changes to residential DR benefits are not limited to the impacts of the new PSH rate, however. The residential PTR rate is also affected in two ways. First, the reduction in event hours affects the PTR DR benefits. Secondly, SDG&E proposes to reduce the credit to $0.50 cent/kWh in the second year of the program. DRA used this $0.50 value since the lower credit would apply to more years than would the initial starting value of $0.75/kWh. This single change, relative to the AMI proceeding, produced by far the largest reduction in benefits. The two changes together produce a reduction in benefits of $27.4 million. The specific changes are described below:

1. **Event Hours**. The SDG&E proposal is based on 31% less event hours, as was the case with PSH. A 31% decrease in DR benefits from the start point of $47.7 million creates a loss of $14.8 million (= .69 x $47.7 million). This leaves a DR benefit balance of $32.9 million.
2. **Altered PTR Credit**. DRA used a PTR credit for the AMI proceeding of $0.65 instead of the more current $0.75. This is reduced to $0.50 in the current proceeding. Again price ratios can be used to derive a proportional DR benefit loss. The price ratios indicate a 38.3% decrease in DR benefits. The impact is large because the incentive reduction occurs while the underlying price has increased from $0.149 to $0.186. DRA applies the 38.3% decrease to the cumulative balance above ($32.9 million), and thus results in additional loss of $12.6

[28] A.10-07-009, Ch. 3, July 6, 2010, p. WGS-21.

> million in residential DR benefits on top of the $14.8 million loss above. Thus the total loss is $27.4 million, and the remaining benefits are $20.3 million.[29] This estimate is only for those customers without enabling technology. Including the DR benefit for customers with enabling technology would only increase the DR benefit loss.

Combining the $27.4 million loss for PTR with the gains from PSH results in a net loss of $23.0 million. These calculations have been done, as described above, assuming that the new PSH recruits did not come from 50% of PTR customers that are already “aware and active.” This is the assumption most favorable to SDG&E. Had the new PSH recruits come from the “aware and active” PTR participants, the DR benefit loss would be an additional $2.4 million[30]. This is a potential loss that DRA does not include in its total.

Of the $118.1 million in program costs, SDG&E attributes $22.9 million incremental costs to the PSH program.[31] DRA initially estimated a modest DR benefit of $4.4 million. However, after changes to the PTR incentives were considered, the cumulative DR benefits became substantially negative at $23.0 million.

E. Small C&I DR Benefits

After adjusting for the increased avoided capacity costs ($67 per kW-year) DRA found the AMI Small C&I DR benefits to be $8.6 million . For Small Non-Residential customers, SDG&E describes how the PSW rate will be substituted for the PTR program assumed in the AMI business case. In regard to this replacement of the old for the new rate plan, SDG&E simply states,

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[29] DRA Workpapers.

[30] $2.4 million is 12% of the cumulative PTR DR balance of $20.3 million. The 12% is derived from subtracting 6% recruits from an underlying 50% participation rate. 6/50 = 12%. Note the rate would be the same (12%) but the impact would be larger if applied to the start PTR DR benefit figure of $47.7 million. 12% of this figure is $5.7. This would be the impact in absence of the other corrections for event hours and price incentives, or if calculated first before these other adjustments.

[31] DRA DR-011, Q.1.

> The demand response achieved from small non-residential customers under PSW would be the same as the expected demand response under PTR in the AMI case.[32]

Therefore, for small non-residential, SDG&E is expecting *no* incremental DR benefits. While SDG&E makes no claim of increased DR benefits, it attributes $95.2 million of the Dynamic Pricing proposal costs to PSW.

DRA, however, notes that the DR benefits for the Small C&I rate class will be undergoing several significant changes.: 1)As with the PSH rate, there is a 31% decrease in the number of event hours with the PSW program, 2) SDG&E states that the participation rate of PSW is expected to be 80%, as opposed to 33% for PTR[33] and 3) SDG&E also reduces the PSW incentive from $0.65 to $0.20 as an inducement to retain PSW customers.[34] SDG&E notes that at this rate, the adder is set at "15% of the cost-based level."[35] SDG&E did indicate that it plans to file in the future to ramp up the incentive to be more cost based.

For the participation rates, PTR has a 100% enrollment rate and a 50% awareness rate, but only those with programmable thermostats ("PCT") (33%) are assumed to be actively participating.[36] Although the PCT build out is not expected to be complete until 2013, DRA accepts the use of a 33% participation rate.[37] Assuming that one-third of small business customers will acquire PCTs may be overly optimistic, but this is offset by the fact that assuming no response from those not having PCTs might be overly pessimistic. The 80% participation rate that SDG&E expects for PSW, however, does appear overly optimistic, especially since SDG&E makes no accounting of how PSW will attain better participation

[32] DRA DR-008, Q.2c.

[33] DR DRA-08 Q. 1b and Q.2a

[34] A.10-07-009, Chapter 4, July 6, 2010, p. Attachment RWH-1, A.05-03-015, AMI Testimony, Ch 6, March 28, 2006, p. SSG-4 & SSG-26.

[35] A.10-07-009, Ch 4, July 6, 2010, p. RWH-9, lines, 21-22.

[36] DR DRA-08 Q.1b and A.05-03-015 Ch 6, Demand Response Benefits, March 28, 2006, p. SS6-26, D.07-04-043, FOF 17, p.91.

[37] A.05-03-015, Ch 6, Demand Response Benefits, July 14, 2006, footnote 21, p. SG-29

rates without dramatically increased PCT saturation. DRA also notes that the PSW participation target of 80% does not come with an estimate of how many are actively providing DR benefits. Nonetheless, for the following calculations, DRA will accept this participation rate. The changes to the DR benefits are shown below.

1. **Event Hours.** A 31% decrease of event hours will decrease benefits 31%. The Small C&I DR benefits have a starting balance of $8.6 million. A 31% decrease would be $2.7 million. The remaining balance would be $5.9 million.
2. **Participation Rate.** SDG&E hopes to retain 80% on PSW as opposed to 33% active participation on PTR. If the 80% participation rate is granted and these customers are also actively providing DR benefits, then this would create a 2.4 fold increase in benefits. This would lead to an increase in benefits of $8.3 million for a cumulative total of $14.2 million.
3. **Incentive Prices**. The current proposal is to lower the incentive price from $0.65 to $0.20. Price ratios are created using the Small C&I base rates ($0.171 for AMI/PTR and $0.194 for Dynamic Pricing/PSW).[38] The ratio of the new deflated incentive prices to the previous is 27.1%. Therefore, the DR benefits would decrease to $3.9 million, or less than half of the starting total of $8.6 million.

DRA notes that if SDG&E does double its incentive adder from $0.20 to $0.40, that the DR benefits would double to $7.8 million and almost be at the current level of benefits. Therefore, it is plausible, as SDG&E claims, that it will not suffer a loss of DR benefits for the Small C&I rate. However, DRA believes this is optimistic at best, since the conclusion also rests on a very optimistic evaluation of participation rates. Although optimistic, DRA did not challenge SDG&E claim that it will not lose DR benefits for this rate class for the purpose of making this benefit calculation.

[38] A.05-03-015, AMI Testimony, Ch 6, March 28, 2006, p. SSG-4 & SSG-26, A.10-07-009, Ch 4, July 6, 2010, Attachment RWH-2, line 4.

F. Medium and Large Nonresidential DR Benefits

Many medium and large non-residential accounts are already on time variant rates. SDG&E plans to move the remaining accounts to the CPP-D ("Peak Shift Plus at Work") rate that features load protection in the form a of customer reservation charge (CRC)) with an opt-out to a TOD rate plan.[39] The focus of the 2010 Dynamic Pricing is not these customers however, and SDG&E listed no increased DR benefits for these rate classes when data requested.[40]

G. Associated Benefits

When combining the findings for both non-residential and residential rate classes, DRA finds a $23.0 million decrease in net DR benefits even before considering the proposal costs. DRA next reviewed the full range of benefits promised by the AMI proposal in order to determine which ones were linked with DR benefits. Many benefits are not linked to changes in DR benefits. For example, the operational benefits from reducing meter reading staff from AMI are unaffected by changes in load. Similar conclusions were made about theft detection and grid safety benefits.

In contrast, the environmental benefits, avoided transmission costs, and other DR program costs would be affected by each MW change in load prompted by this proposal's change in Demand Response. DRA found that these additional benefits were almost in a one-to-one ratio (90%) with the DR benefits. Therefore, the $23.0 million in DR benefit losses could be expected to generate an additional $20.7 million loss of environmental benefits, unavoided transmission costs, and negated reductions in DR program costs. Thus, DRA finds a total decrease in benefits of $43.7 million in addition to the $118.1 million proposed expenditures.

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[39] A.10-07-009, Chapter 2, July 6, 2010, p. GCB-10, lines 16 – 19.

[40] DRA DR-008 Q.2c.

IV. CONCLUSION

DRA estimates that SDG&E's new dynamic rate programs would result in $43.7 million fewer benefits than was assumed in SDG&E's Advanced Metering Infrastructure ("AMI") business case DRA's analysis and calculation of incremental benefits in this chapter thus, casts serious doubts on the value of SDG&E's dynamic pricing proposals.

CHAPTER 5

INFORMATION TECHNOLOGY, OUTREACH, EDUCATION COSTS

DALE PENNINGTON & ERIC NELSON

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CHAPTER 5

INFORMATION TECHNOLOGY, OUTREACH, AND EDUCATION COSTS

(Witnesses Dale Pennington & Eric Nelson)

I. SUMMARY AND RECOMMENDATIONS

This testimony presents the Division of Ratepayer Advocates' ("DRA") recommendations regarding the Customer Outreach & Education and Information Technology ("IT") elements of San Diego Gas and Electric's ("SDG&E") dynamic pricing proposal.

DRA recommends that the Commission dismiss SDG&E's dynamic pricing application. DRA further recommends implementing Time of Use ("TOU") rates before Critical Peak Pricing ("CPP"), starting with a TOU pilot. SDG&E provided insufficient justification for its requested costs to support dynamic rates. Its testimony and responses to data requests show a lack of rigorous planning for such significant ratepayer expenditures. SDG&E has not performed adequate analysis and research to ensure that the investments will be cost-effective, just and reasonable. Its IT testimony showed a lack of high level system design documentation. Hence, it is not possible to verify whether the proposed IT costs and timeline are reasonable. SDG&E has not investigated alternative approaches to reduce IT costs. In the absence of a strategic IT plan and roadmap, it is impossible to determine how the proposed purchases and overall approach fit into the end-vision for SDG&E's information technology capabilities.

Based on the reasons explained above and discussed elsewhere in this testimony, DRA makes the following recommendations:

1. The Commission should deny SDG&E's dynamic rate program funding request at the present time.

2. SDG&E should propose a first phase of effort focused on:

    a. A pilot program for TOU rates:

1. The pilot program should provide for at least two TOU pilot rate structures, one with prices that are as close as possible to the underlying marginal cost of service, and one that has less of a range between peak and non-peak rates.

2. The pilot program should include a customer outreach and education plan to support the TOU rates.

3. SDG&E should assess the feasibility and cost of using third-party hosted IT providers for the TOU pilot to determine if it is a cost-effective alternative.

b. IT system enhancements required to support a TOU rate structure for SDG&E's full customer base.

3. SDG&E should employ cost-effective customer outreach methods to promote TOU rate options. Examples of such methods include:

a. Clear prices and schedules for the TOU rates printed on bills and on magnets that customers would place on major appliances to influence their behavior changes.

b. Press releases, notifying local TV and print news agencies for the new rates.

4. SDG&E should develop a clear roadmap for its IT systems with project interdependencies delineated to show how new initiatives fit into the overall end-vision for SDG&E's information technology capabilities. This should show the timeline for the IT projects required for this initiative and how they fit into the SDG&E overall IT plan.

5. SDG&E should perform cost comparison studies to assess the relative costs of continually upgrading its legacy systems versus deploying commercial off-the-shelf ("COTS") packages.

6. SDG&E should define a formal process for ensuring that there are no overlaps in funding between rate cases for IT. DRA recommends that an internal, independent third-party (outside IT) should govern/administer this process.

II. SUMMARY OF SDG&E'S PROPOSAL

SDG&E proposes to provide time-variant pricing and default dynamic rates to its small nonresidential customers, and to offer optional time-variant and dynamic pricing to its residential customers. SDG&E requests funding to develop the IT systems and customer education and outreach necessary to support time-variant and dynamic pricing for all of its customers.

SDG&E provided this table to show the proposed timeframe for rolling out dynamic pricing to all of its customers:

Illustrative Timeframe for Dynamic Pricing for SDG&E Customers

Customer Class	Tariff	Rate Design Application	2011	2012	2013	2014
Residential	**Peak Time Rebate (PTR)**	Filed in 2008 GRC Phase 2; approved in D.08-02-034	PTR implemented		Reduction in PTR incentive credits.	
	Optional PeakShift at Home (PSH)	2010 Dynamic Pricing Application			Optional PSH implemented (prior to summer 2013)	
	Default PSH or Time of Day (TOD) Rate	Future Rate Design Application				Earliest date Default PSH or Default TOD implemented
Small Non-Residential (< 20 kW): Commercial & Agricultural	**Default PSW**	2010 Dynamic Pricing Application			Default PSW implemented (prior to summer 2013)	
Medium & Large Non-Residential (greater than or equal to 20 kW): C&I and Agricultural	**Default Critical Peak Pricing (CPP) Rate (CPP-D)**	Filed in 2008 GRC Phase 2; approved in D.08-02-034			CPP-D implemented in 2008 for customers with appropriate metering. All remaining customers default to CPP-D prior to summer 2013.	
All Customers	**Optional Real Time Pricing (RTP)**	2012 GRC Phase 2 Application or Future Rate Design Application			Earliest date Optional RTP implemented	

The following is a summary of costs proposed by SDG&E for (1) Customer Outreach & Education and Operations for Peak Shift at Work, (2) Customer Outreach & Education and Operations for Peak Shift at Home, and (3) Information Technology. Note that all costs are in 2009 dollars, and cover the years 2010 – 2015.

A. Customer Outreach & Education Costs

The total cost for Customer Outreach & Education and Operations is $29,200,000 for Peak Shift at Work ("PSW") and $10,105,000 for Peak Shift at Home ("PSH"), shown in the next two tables.

Outreach & Education and Operations Costs for Peak Shift at Work

Area	**Cost**
Research	$2,600,000
Communications (Education, Transition, Customer Care, Anniversary)	$3,700,000
Outreach (Paid Media, Door-to-Door, Other)	$2,600,000
Outreach and Communications Labor	$1,100,000
Website enhancement (design, video tutorials, labor, operations and maintenance)	$3,700,000
Customer Service	$2,500,000
Operations	$6,400,000
Facilities	$6,600,000
TOTAL	$29,200,000

Sources: tables GCB-03, GCB-05, GCB-06 and GCB-06

Outreach & Education and Operations Costs for Peak Shift at Home

Area	**Cost**
Outreach	
- Paid Media, Event Materials, Media/Public Relations	
- SDG&G Bill Inserts, SDG&E Outreach Campaign Partnerships	
- Energy Program Advisor	$1,786,000
Direct Communications	
- Campaigns: Education & Recruitment, Opt-in Confirmation & Welcome Kit,	
Care & Maintenance, Anniversary, Win-Back	
- Advisors: Market, Communication, Load Research	$4,322,000
Research	
- Rate Education, Education & Recruitment, Care and Maintenance and	
Customer Non-Conversion Research	
- Overall Customer Experience Assessment	
- Customer Research Analyst	$895,000
Website enhancement	
- includes web design, tutorial production, web test design with customers	$1,016,000
Operations	
- Employee training	
- labor costs for CSRs, billing analysts and customer programs staff	$2,086,000
TOTAL	$10,105,000

Sources: tables WGS-9, WGS-10, WGS-11, WGS-12, WGS-13 and WGS-14

B. Information Technology Costs

The total IT cost is $32,396,381 for capital items and $9,103,000 for operations and maintenance. This includes the cost to develop the systems required to support dynamic pricing for small non-residential, medium non-residential and residential customers. (Source: table DJS-2)

Information Technology Costs

Area	Cost
Enrollment, Anniversary Management	$1,758,892
Eligibility	$3,891,177
Marketing, Outreach, Education	$3,727,351
Event Management	$1,842,078
Billing	$1,915,283
Online Presentment, Rate Analysis	$13,083,447
Care and Maintenance	$2,578,555
Contingency	$3,599,598
TOTAL	$32,396,381

Source: table DJS-1

III. DISCUSSION

A. CUSTOMER EDUCATION AND OUTREACH

1. SDG&E Provides Inadequate Cost Justification for its Dynamic Pricing Programs.

Fundamental to any customer outreach effort is the need to establish clear and measurable goals. From these, the anticipated benefits to ratepayers can be quantified. These benefits can then be compared to the program costs to determine whether or not the results of the outreach effort justify its cost.

Though DRA has attempted to derive demand reduction benefits in Chapter 4, it is clear that SDG&E did not attempt to do so itself. DRA believes that it is not sufficient to just say that these rate programs are mandated by the Commission, and therefore no cost justification is necessary. The fact that SDG&E did not quantify any benefits is apparent in many data request responses to UCAN. Furthermore, any goals it has provided seem unrealistic:

- In data request response UCAN DR-01 Question 4, SDG&E states that it has not quantified any cost reductions to SDG&E as result of dynamic pricing.
- In data request response UCAN DR-02 Question 12, SDG&E states that "SDG&E has made no assumptions about how load profiles will change under the TimeOfDay rate option, nor how to calculate any change."
- In UCAN DR-02 Question 21 (also from RWH-9 line 21), SDG&E states that "In the proposed PSW rate design methodology the Seasonal Demand Charge and PeakShift Period adder are set at approximately 15% of a cost based level." SDG&E also states that it has not done analysis on how the customer participation rate might change by using levels of more or less than 15%.
- In data request response UCAN DR-01 question 15, SDG&E gives an estimate of how many residential customers it thinks will enroll in a dynamic pricing plan between 2013 and 2015. This estimate is 50,000-100,000 residential customers, or 4-8%. This is more than PG&E enrollment in its current SmartRateTM, which is less than 1%.
- In data request response UCAN DR-02 question 9, SDG&E gives an estimate of how many small commercial customers it expects to remain in the PSW rate of 96,000 or 80%. This is more than SDG&E's enrollment of its largest commercial customers of 61%, and much more than PG&E's enrollment rate in critical peak pricing, which is 37%.
- For residential customers, SDG&E did compare annual bills under the current Schedule DR with the proposed Schedule DR-TOD-C with PSH. These results were provided in SDG&E's Ch 4 testimony, attachment RWH-10. But there is no linkage between this study of bill impacts and participation rate estimates.
- In data request response UCAN DR03 question 23, SDG&E estimated the cost impact for small non-residential customers due to implementation of PSW rates. Again, this information was not clearly connected to the 80% participation rate above.

Even though SDG&E established some performance metrics for the outreach and education programs,[1] specific goals for these metrics have not been set. The only indication of demand response reduction targets that have been set can be derived from information presented in DR-08. That data request asked

[1] As SDG&E stated in Data Request Response DRA-07 question 19, some performance metrics are presented in Chapter 2 testimony on pages GCB-16 through GCB-18.

about the incremental benefits that the rate programs in this application would provide relative to those assumed in the Advanced Metering Infrastructure ("AMI") business case. As discussed in Chapter 4, it was questionable that the over $118 million of funding that SDG&E is requesting in this application could be justified by the incremental demand response benefits. Clearly more work would need to be done to develop a plan for implementing TOU and CPP and an associated outreach and education effort that would produce the benefits needed to justify the project.

2. SDG&E's Outreach/Education Plan is Deficient and it Performs Little Cost Comparison Among Outreach Alternatives

In many data request responses included below, SDG&E shows that it has not yet performed the research and analysis to determine the best and most cost effective methods of educating customers about the proposed new rates. SDG&E states that it will do this analysis in stage 1 of the project, after the project and funding for the project have been approved by the Commission. DRA strongly believes that a customer outreach program of this magnitude cannot be approved until more analysis has been done to show that the means of outreach and education will be effective. For this reason, DRA recommends that SDG&E propose a first phase of effort to design effective outreach strategy for TOU rates, including a TOU pilot.

In data request response UCAN DR-01 Question 11, SDG&E states that it cannot provide analysis to compare outreach alternatives, but states that they have "reviewed the PG&E 2010-2011 Peak Day Pricing Customer Outreach Plan, and is also familiar with published case studies from other out-of-state utilities implementing dynamic pricing, as well as the California Statewide Pricing Pilot".

In Data Request DRA-04 SDG&E states that "An extraordinary effort will be placed in the initial design and development of the outreach plan. Some details of the plan will only emerge later in the design process" In data request response DRA-04 question 1, it states "The communication methods used in Stage

2 and Stage 3 will be determined as a result of the work performed in Stage 1. A mix of communication methods will be used to communicate rate information, but no decisions on the final mix have been made." In Data Request Response Greenlining DR01 question 1.2, SDG&E states "SDG&E believes that the burden being placed on the outreach campaign to accomplish these objectives requires a significant investment in research and design. SDG&E cannot perform this research without Commission approval."

The lack of clear planning is substantiated in other data request responses. In data request response UCAN DR03 question 10, SDG&E states that it does not have estimates of how many small commercial and agricultural customers it plans to reach through the ten avenues of customer education and training specified in the plan. SDG&E states "This project is sponsoring a quantitative research study, planned for 2011, that will be designed to answer this very question."

In data request response UCAN DR06 questions 18 and 24, SDG&E states that it plans to conduct four focus groups in 2011 to get feedback from customers to design the dynamic pricing rate education material. It also states that it plans to conduct online co-design panels in 2012 to help to determine the best channels to deliver information on PSH to the customer.

This is not to say that SDG&E has done no research. In Data Request Response UCAN DR06 question 16, SDG&E states that it did do customer segmentation analysis to target outreach messages to customers more likely to be interested in the PSH rate option. Also, in UCAN DR-01 question 11, SDG&E states that they incorporated lessons learned from implementing Critical Peak Pricing Default ("CPP-D") into the current outreach proposal. More research, however, is necessary before embarking on a $118.1 million effort.

DRA strongly believes that an outreach program of this size cannot be approved until this initial research and design is done to ensure that the methods used will be successful and that they will be cost effective. DRA recommends that SDG&E propose a first phase of effort focused on a TOU pilot and the customer outreach and education to support TOU rates. This should include a detailed review of other utilities' TOU programs and the various methods of communicating the program to customers. Each method should be evaluated for the costs and the effectiveness of the program.

3. A More Measured Approach to Implementing the New Rate Structures Would Lead to Greater Success at Less Cost

DRA recommends that Time of Use rate structures be deployed and given time to stabilize before introducing Critical Peak Pricing. The reasons for this are elaborated upon in Chapter 1 of DRA's testimony. This section provides additional information to substantiate this recommendation.

Fundamental to any marketing plan is to market and offer a product that ratepayers will understand and will believe offers them tangible benefits. The conflation of multiple rate programs, being initiated at the same time, is confusing to ratepayers and decreases the probability of adoption. Ratepayers will need time to adapt to the TOU rate structure. It will take time for them to understand the rate structure, to see the impacts that the rate structure has on their bill and to change their usage patterns.

Implementing multiple rate programs simultaneously also makes it impossible for SDG&E to analyze the effects of each program so that it can set goals for the next phase of implementing dynamic rates. SDG&E will need time to analyze the results of the TOU rate structure. SDG&E will need adequate time to review real consumption data, develop appropriate pricing levels, analyze usage patterns by user community, and target set groups for energy reduction. This kind of analysis will also help SDG&E to target its advertising to make it more effective. Several iterations of adjustments to the TOU program may be needed in order to reach the goals of demand reduction.

After the affects of the TOU program are understood, additional reduction incentives may then be needed to reduce demand. One of those may be CPP. However it is also possible that we will see greater cost reduction than anticipated with the time-variant pricing of TOU, and additional pricing options may not be required to meet energy reduction goals. The fact that TOU programs have not been given an adequate chance to succeed is discussed further in Chapter 1.

A more measured approach will also reduce the cost of implementing these rate programs in the long run. The outreach and IT components for TOU can be provided at a lower cost since TOU is a less complex rate, and one that does not require a sophisticated notification schema. Clearly, not having a well-developed plan for deploying either the IT or outreach components of dynamic pricing risks wasting money because these efforts may not be successful.[2]

The results from SDG&E's focus groups with small business customers support the opinion that TOU and CPP are too much to introduce to the customer in the same time frame. In UCAN DR03 question 1, SDG&E states that it has conducted two focus groups with small business customers with 16 participants in total. SDG&E states that one of the major findings of the focus group was that "some [participants] had particular difficulty understanding the concept that the rates have a seasonal as well as a time of day component." In response, to this finding, SDG&E reduced its TOD rate periods from three to two. Additionally, PG&E's Feb 14, 2011 Petition to Modify D.10-02-032 reaches the same conclusion that TOU should be given a reasonable time to work prior to implementing CPP.[3]

Another finding from the focus groups was that participants said they wouldn't be able to respond to time-of-use rates because on-peak hours coincide with the time when they are serving customers and they could not make adjustments to energy use. To address this, SDG&E: "1) purposely maintained the modest differential between on-peak and off-peak; 2) proposed a tempered Peak-Shift at Work ("PSW") rate; 3) extended the implementation period to 2013 to allow for customer education; and 4) proposed robust customer outreach and

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[2] The IT system is discussed further in Section III.B "Information Technology".

[3] PG&E Petition to Modify D.10-02-032, p.2.

education programs and tools to help customers understand their rate options and to help them learn strategies to mitigate the impacts of higher on-peak rates."

TOU will require less customer education and is a stable and simple pricing model. Once the rates are set for the year, they are consistent and can be easily conveyed to the customer. The pricing and schedule for the full calendar year can be printed on the bill. The on-peak, off-peak and mid-peak daily time periods and summer/winter dates can also be printed on magnets that the customer can place on their dishwasher, washing machine, or other appliances, as described in the next section.[4] This stability will help the customer understand the rate and modify their behavior around it.

Conversely, CPP is a dynamic pricing model which requires advanced notifications for peak days. More education will also be required to help customers understand the model, to anticipate the peak day notifications and to change their behavior.

4. Performing TOU Outreach and Education

The following is an example of how a TOU rate can be summarized to the customer on the bill or on magnets, which would be placed in the customers' home or office. These would easily remind customers about the time-varying rates and influence their usage pattern. The costs and time periods could be displayed in the following manner:

Time-of-use Prices		
	Summer May 1 – Oct 31	**Winter** Nov 1 – April 30
On-peak	21.3 ¢/kWh	15.6 ¢/kWh
Mid-peak	19.5 ¢/kWh	15.1 ¢/kWh
Off-peak	18.0 ¢/kWh	14.6 ¢/kWh

[4] DRA acknowledges that magnets are not included in the costs for this rate case. If DRA's recommendation is accepted to start with TOU rates and not CPP, then these costs could be added to a TOU rate case.

Time-of-use Schedule			
Summer May 1 – Oct 31		**Winter** Nov 1 – April 30	
8pm – 8am	Off-peak	9pm – 7am	Off-peak
8am – 11am	Mid-peak	7am – 11am	On-peak
11am – 8pm	On-peak	11am – 9pm	Mid-peak

These costs and time periods are merely illustrative, but are included to demonstrate that a TOU rate structure can be easily displayed in a small space such as the customer's bill or a magnet.

In addition, DRA recommends that a strong emphasis be placed on press releases, press conferences, and notifying local TV and print news agencies of the new rates. These are mediums that are low cost and can reach a large number of people.

5. Designing a Customer Outreach Program for TOU

DRA recommends that SDG&E consider a pilot program to help design its outreach program for TOU. Pilot programs, by definition, are easier to define, estimate, measure, and evaluate. In the pilot, the outreach plan can be tested on a smaller group and refined before implementing it for the entire customer base. Also, future cost estimations can be based on the pilot program to make them much more precise.

A TOU pilot program should provide for at least two TOU pilot rate structures, one with prices that are as close as possible to the underlying marginal cost of service, and one that has less of a range between peak and non-peak rates. This will allow SDG&E to assess if a greater difference in peak and non-peak rates entices the customer to modify their consumption behavior.

In the pilot program, multiple methods of communication and education for TOU rates should be tested. Based on their success, SDG&E can choose the most cost-effective methods of communication when rolling out TOU rates to the full customer base. The pilot program will also allow SDG&E to track real savings data for real customers using TOU rates. This data can then be used in communications to other customers, and to show them real savings that other customers have obtained by using TOU rates.

The TOU pilot program methodology can be also used as the structure for additional pilots for more advanced pricing structures like CPP. In addition, based on lessons learned from the TOU program like participation rates and KW and kWh reductions, SDG&E can then develop the business case for CPP and other pricing structures.

B. INFORMATION TECHNOLOGY

1. SDG&E's IT Cost Proposal Cannot be Reasonably Verified.

As with Customer Outreach and Education, DRA has not seen the level of planning necessary for a successful outcome in the IT area. As-is and to-be high-level system and integration architecture documents have not been provided as requested in DR-07, Questions 01 and 10. Also missing are high-level schedules for the IT projects included in this effort, high-level risks, and system acceptance criteria, as requested in data request 18, Question 01. Without this high-level analysis and design, it is difficult to verify whether the budget and timeline are reasonable.

This can be contrasted with the PG&E's showing in its GRC2011-Phase III Rate Case. There, PG&E provided a high-level to-be system design (GRC2011-Ph-3_Dr_DRA_001-Q09Atch01). Also, detailed IT work packages and estimates were provided in response to data requests (GRC2011-Ph-3_DR_DRA_001-Q01Atch01 through GRC2011-Ph-3_DR_DRA_001_Q01Atch06).

While IT costs, at a functional level, are presented in this application (as provided in response to DRA-06 in the document 'Chp 5 (Shulman) - IT Costs Workpapers REVISED 2010_11_19.xls'), they are not tied to specific projects, requirements, or ratepayer benefits. As noted in Data Request Response DRA-03 Question 01 "SDG&E has not yet created a detailed project plan for Stage 1 and

Stage 2 beyond what is included in the revised work papers and cannot determine the cost for the tasks within each phase." The lack of planning and documentation at this stage makes it difficult or impossible to benchmark this project's costs against similar efforts.

The Commission has made it clear that it cannot authorize funding requests unless there is clear evidence that the activities and material are necessary and optimal, and the associated costs are reasonable. For instance, in the last PG&E rate design window case, the Commission rejected PG&E's contingency request for its IT budget and explained:

> We will not include contingencies in the cost recovery authorized by this decision. PG&E's contingency request totals over $32 million, or approximately 25.6% of the forecasted costs. This represents a substantial amount of unspecified work that has not, and by PG&E's cost recovery proposal will have not, specifically been reviewed for reasonableness before being included in rates…. We are concerned that our regulatory obligation to ensure just and reasonable rates is being eroded by including such large portions of project costs in rates, without having determined the reasonableness of the costs. At this point, ***we do not know what amount of contingencies will actually be expended, and for any amounts expended, what the related activities or materials are, whether the related activities or materials are necessary and optimal, and whether the associated costs are reasonable***.[5]

Though this statement was made in regard to contingency allowances, the underlying standards for justifying cost requests apply to any cost category. SDG&E's cost requests have not met the above-mentioned standards.

Additionally, DRA would like to see a formal process to ensure that there are no overlaps in funding between rate cases, and recommends that an independent third-party (outside IT) should govern/administer this process. SDG&E stated in data request response 15 and data request response 16

[5] D.10-02-032, mimeo, pp.126-127, Emphasis added.

that there are no overlaps between the costs requested in this rate case and the costs requested or approved in other rate cases. However, SDG&E does not provide a methodology or formal process for estimating incremental costs, except to say that they discuss between teams.

2. SDG&E Failed to Consider Alternatives to Reduce Its Costs

One way to potentially reduce IT costs is to replace older legacy systems with Commercial off-the-shelf ("COTS") packages. For example, many large energy utilities all over the world are replacing their legacy Customer Information Systems ("CIS") with COTS Customer Care and Billing systems. DRA provides for reference Appendix A (SAP Utilities Projects) and Appendix B (CIS-COTS Conversion Study).

The available COTS packages already have built-in some of the customizations that need to be made to SDG&E's IT systems for CPP. Purchasing software that comes with this industry-specific functionality is more cost effective than building it internally. Developing software is not a core competency of an energy distribution company, but it is a core competency of a software firm.

In the AMI rate case (D.07-04-043 page 18), it states that SDG&E's "AMI technology solution will at a minimum:

- Be a technology independent, next generation solution supporting:
    - Open architecture;
    - Fully upgradeable;
    - Scalability;
    - Flexibility; and
    - A complete end-to-end solution.
- Be fully integrated with existing operational infrastructures.
- Be able to support additional functionality at a later date without the need for significant additional systems hardware."

It does not appear that SDG&E attempted to develop a similar architectural concept for its other core legacy applications.

One specific example of a system where a COTS package may be cost effective is in replacing the decade-old legacy Customer Information Management ("CISCO") system. Continuing to operate the legacy CISCO system will require significant costs to modify the program to reach the current technical requirements. For this case alone, the budget for CISCO is (derived from 'Chp 5 (Shulman) - IT Costs Workpapers REVISED 2010_11_19.xls') as follows:

CISCO costs for this rate case

Enrollment, Anniversary Management	$ 13,230
Eligibility	$ 152,686
Marketing, Outreach, Education	$ 29,106
Event Management	$ 120,887
Billing	$ 706,767
Online Presentment, Rate Analysis	$ 1,088,495
Care and Maintenance	$ 399,401
TOTAL CISCO	$ 2,510,573

There are also significant CISCO costs in the General Rate Case (Mr. Nichols' testimony p. 26, 27). The Estimated CISCO cost for Test Year 2012 for IT maintenance and enhancement programming support is $3,639,000.

The legacy CISCO system will require a higher level of ongoing total cost of ownership ("TCO") in comparison with COTS systems since it is based on older technology and programming languages. This is especially true for integration costs when comparing a legacy mainframe system to a newer technology COTS package that has integration functionality built in. As stated in Data Request Response DRA-03 question 5, "CISCO, CRM and My Account will be enhanced during the project along with significant systems integration between these systems".

Also as stated in data request DRA-07, response 05, the legacy CISCO system architecture is not scalable to handle the additional rate analysis required by CPP. A COTS package is designed to handle these kinds of volumes. This is further discussed in Appendix A: SAP Utilities Projects. As stated in data request DRA-07, response 04, no cost-benefit analysis has been done for replacing CISCO with a COTS package.

DRA has performed a preliminary analysis on implementing a COTS package for the SDG&E CISCO, Customer Relationship Management ("CRM"), Meter Data Management System ("MDMS") and online presentment & rate analysis systems. This is a preliminary analysis and so a range of costs is given. To get a more accurate cost, SDG&E would need to assemble a detailed cost/benefit analysis of these or other available COTS systems.

Application costs

Application	Cost
Northstar Meter Sense - Residential and commercial online presentment and rate analysis - Usage analytics - MDMS - Integration to CIS - Covers various rate structures including TOU and CPP - the cost includes the implementation, but not licensing fees	$5,000,000 - $6,000,000
SAP CIS - Billing, Invoices, including real-time pricing billing - Customer Relationship management - MDMS - Limited customer web portal (does not include online presentment and rate analysis) - Integration between CRM, billing and web portal - the cost includes the implementation, but not licensing fees	$15,000,000 - $20,000,000

Initially, the cost of implementing a COTS solution may be similar to or greater than the costs of enhancing legacy solutions. While one saves in development costs by obtaining a new COTS system, there are additional costs to change business processes and invest in new IT infrastructure. These include, for example, the cost of replacing the legacy mainframe architecture with a new n-server architecture and network. Also, COTS systems will have on-going licensing fees which are not included in the above implementation costs. Licensing fees will vary according to the number of modules implemented and the negotiated contract. A detailed analysis of requirements of the system as a whole and input from the vendor would be required to estimate on-going licensing costs.

In general, the total cost of ownership ("TCO") of a COTS system is by definition less than the cost of maintaining a custom developed system. COTS vendors stay in business by providing software for less than what it would cost for an individual company to create it themselves, and do so by spreading the costs over multiple clients. Some of the key savings of COTS systems in the long term are:

- Additional functionality, which may be needed in the future (for example fully capable demand pricing rating engines, bill generation packages, electronic bill presentment & payment ("EBPP"), integration to Customer Relationship Management ("CRM") and Meter Data Management System ("MDMS") systems, etc.), are already built into the product and the utility will save the cost of having to incrementally build and re-build those capabilities in a legacy environment
- New industry specific software updates are included as part of the licensing costs, as opposed to developing all new functionality in-house
- The new systems will be able to operate on a unified technology platform instead of having to operate two separate environments (mainframe and web/server-based).

DRA recommends that SDG&E perform a cost/benefit analysis of replacing its legacy CISCO system with a COTS system. This may reduce the total cost of ownership of this system and may also reduce development time and cost for future rate programs.

3. SDG&E Should Assess Using a Third-party Hosted IT System for a TOU Pilot Program

DRA recommends that SDG&E consider using third-party hosted software to implement a TOU pilot. SDG&E should assess the feasibility, costs and benefits of using a third-party hosted IT system, to determine if it is a cost-effective alternative.

Using a hosted software solution for a pilot program for TOU rates would allow SDG&E to test the new rate on a small customer group for less cost and less time to market than developing the system in house for its full customer base.

SDG&E could then use the results of the pilot program to build the business case for the new rate, to assess the efficacy of customer education and outreach program, and to better estimate the cost of offering the rate to its customers.

4. IT Strategic Plan and Roadmap

The IT costs for this rate case, the pending General Rate Case and the previously approved AMI rate case reveal not only the enormity and complexity of SDG&E's overall IT upgrade effort, but also the significant costs of these IT upgrade programs when added together. It is in the best interest of the Commission and SDG&E to treat these efforts holistically, in order to reduce overall cost and duplication of effort.

Many of SDG&E's core IT systems are being updated in different but dependent projects, on different timelines. A list of the IT systems to be enhanced for this initiative is included in Appendix D.

An overall IT project schedule and roadmap was requested in Data Request 18, Question 03. SDG&E stated that some of this information could be found in the General Rate Case application, but a project roadmap with high-level dates was not found in the GRC application or supporting testimony. SDG&E also objected to the request for an overall IT roadmap as "overbroad and not reasonably tailored to lead to discovery of admissible evidence in this case". However, DRA believes that it is crucial to understand how these IT projects fit into SDG&E's overall IT plan and schedule. Without robust planning and management, interdependent projects can result in increased individual projects costs, extended project timelines and duplication of effort.

DRA recommends that SDG&E develop a clear roadmap for its IT systems to show how these initiatives fit into the overall end-vision for SDG&E's information technology systems. The roadmap should show the high-level timeline for IT projects and should point out any interdependencies between projects.

IV. CONCLUSION

DRA firmly believes that a delay in the implementation of dynamic pricing is in the best interest of all the ratepayers. Such a delay for CPP is warranted in order to allow the ratepayers time to adapt to TOU rate structures and to allow SDG&E time to analyze the results prior to providing another pricing product.

In addition to separating the implementation of TOU and CPP, clear and measurable goals for the project need to be set, and clear benefits to the ratepayers need to be quantified. In order to carry this out, it would be desirable for SDG&E to have the AMI system fully deployed and so that it can have a database of energy usage that is fully populated. One year of interval data should be used for the baseline of customer consumption. When AMI is fully deployed, SDG&E will have accurate usage profiles and will be able to build out its strategy for TOU to target peak load reduction and energy reduction targets. In addition, different TOU rates and time windows can be evaluated against real interval usage data.

It is true that individual customers will have one year of billing data which they can use to decide whether to opt in or opt out of rate alternatives. They will also have at their disposal rate analysis tools through SDG&E's web portal. SDG&E as a utility, however, will not have interval data for all of its customers to be able to analyze and design the program effectively.

More analysis including case studies of other utilities is necessary to show that the proposed outreach budget is reasonable and that the funds will be used effectively. DRA suggests that a working group modeled after the AMI Technical Advisory Panel ("TAP") be formed to co-develop a comprehensive strategy for moving forward that addresses some of the concerns and gaps identified in this testimony. Alternatively, these efforts can be rolled into the existing TAP if appropriate and practical.

DRA recommends that SDG&E carry out a TOU pilot as discussed in this testimony. DRA recommends that the design of the pilot be supported by the Technical Advisory Panel. In the pilot program, multiple methods of communication and education can be tested. Based on their success, SDG&E can choose the most cost-effective methods of communication when rolling out TOU rates to the full customer base.

From an IT perspective, more detailed system design documentation is required to determine whether the proposed IT costs are reasonable. Also, cost/benefit analysis has not yet been done to determine whether COTS systems would reduce new development cost and total cost of ownership for SDG&E's IT systems in the long term. Lastly, an overall IT plan and roadmap is needed to determine how these projects fit into the overall end-vision for SDG&E's information technology capabilities.

V. APPENDIX A

Reference document: SAP Utilities Projects

Company overview

Vision and strategy for product area & product roadmap

Utility customers

Description of proposed solution (i.e. products / modules and supporting tools)

Why is this the right choice for Atmos Energy, right now?

Implementation support

Pricing

Conclusion

39 of Global 50 Utilities Run SAP

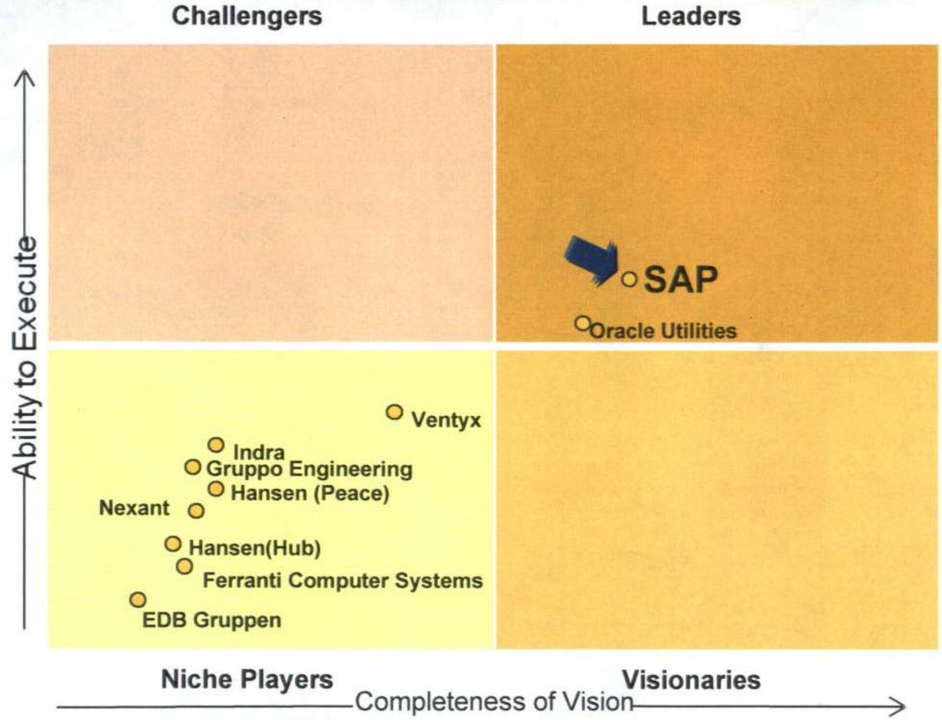
Rank	Company	Country	SAP	CR&B
17	GDF Suez	France	✔	✔
27	EDF Group	France	✔	✔
43	ENEL	Italy	✔	✔
57	RWE Group	German	✔	✔
62	E.ON	German	✔	✔
87	Iberdrola	Spain	✔	✔
129	National Grid	UK/USA	✔	✔
171	Exelon	USA		
195	Korea Electric Power	South	✔	
201	Southern Co	USA		
206	Kansai Electric Power	Japan	✔	
225	Dominion Resources	USA	✔	
226	FPL Group	USA	✔	✔
236	Scottish & Southern	UK		
239	EDP-Energies de Portugal	Portugal	✔	✔
258	Chubu Electric Power	Japan		
260	EnBW-Energie Badan	German	✔	✔
269	Duke Energy	USA		
281	PG&E	USA	✔	
282	Veolia Environment	France	✔	✔
284	American Electric	USA	✔	
310	FirstEnergy	USA	✔	
312	Eletrobras	Brazil	✔	
313	Entergy	USA	✔	✔
317	NTPC	India	✔	✔

Rank	Company	Country	SAP	CR&B
323	Edison International	USA	✔	✔
333	Union Fenosa	Spain	✔	
335	Pub Sve Enterprise	USA	✔	
336	CEZ	Czech	✔	✔
339	Gas Natural Group	Spain	✔	✔
340	Consolidated Edison	USA	✔	
361	Fortum	Finland		
409	Sempra Energy	USA	✔	✔
415	Tokyo Electric	Japan		
421	TransCanada	Canada	✔	
424	Williams Cos	USA	✔	
445	AES	USA	✔	✔
449	Kyushu Electric	Japan	✔	✔
458	Progress Energy	USA	✔	
479	CLP Holdings	Hong	✔	✔
487	PPL	USA		
492	Excel Energy	USA		
540	Tokyo Gas	Japan		
549	Huamemg Power Intl	China	✔	
575	Tenaga Nasional	Malaysia	✔	✔
579	Centrica	UK	✔	✔
592	Edison	Italy	✔	✔
600	NRG Energy	USA	✔	
617	Tojoku Electric	Japan		
626	Saudi Electricity	Saudi	✔	

Selected SAP CR&B Customers

A strong focus in utilities industry

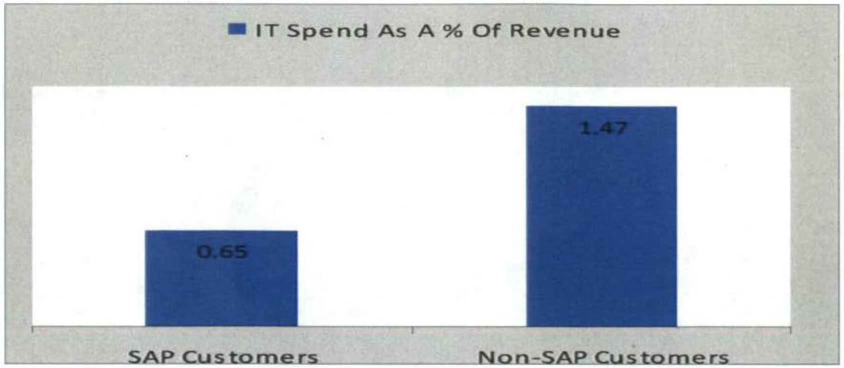
- 750+ utilities managing 2.5+ billion customer bills with SAP
- 65% CIS and 33% ERP market share (Gartner)
- Over $2B annual spend in R&D
- 12,000 employees in product development, R&D



Source Gartner (June 2009)

Comparison of Top 25 North American Utilities - KPIs			
Averages	ROA	ROE	Profit margin
Companies with SAP implementations	4.15%	14.66%	9.50%
Companies with non-SAP implementations	3.91%	10.00%	8.15%

Source : SAP Analysis; 2008/2009 data



Source : ASUG data, n=214

Selected SAP CR&B Customers

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

"I could not find a gas utility that had implemented anything other than SAP in North American in the last five years." – Brunson White, CIO, Energen

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

CenterPoint Energy

Live Since 1999

3.2 Million Gas Meters

6 states: TX, MN, AR, LA, MS, OK

SAP enabled standardized processes across 6 states.

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

Live Since 2003

690,000 electric meters

320,000 gas meters

Largest municipal utility in the United States

Advanced Builder's Portal

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

ENMAX

Banner Replacement

Live Since 2008

400,000 electric meters

150,000 gas meters

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

CITY of PALO ALTO

Banner Replacement

Live Since 2008

45,000 electric meters

45,000 gas meters

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

Terasen Gas

Terasen Gas

2011 go live

935,000 gas meters

The Company believes that the SAP CIS solution chosen is, in part, ***a market leader as a result of significant investment by the vendor***. …Terasen Gas believes that this investment, in addition to the ***very large and varied SAP skill set in the marketplace*** from which to draw…***There is no way to reasonably predict the cost associated with the ongoing enhancement of the current CIS***.

From Terasen's Rate Case

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

ENBRIDGE

<u>2009 go live</u>

<u>1.9M gas meters</u>

<u>Service Area: Ontario, Quebec, New York State</u>

<u>Oracle Financials</u>

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

BC hydro

2003 go live

1.7M electric meters

Oracle Financials

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

e·on

2009 go live

900,000 electric meters

300,000 gas meters

Oracle Financials

2 States: KY & VA

Significant customer self service capabilities

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

Consumers Energy
Count on Us

<u>2008 go live</u>

<u>1.8M electric meters</u>

<u>1.7 M gas meters</u>

<u>Single Roll Out of ERP & CRB for 3.5M meters</u>

<u>AMI thought leader</u>

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

FirstEnergy

1999 go live

4.5M electric meters

3 states – NJ, PA, OH

Advanced Collections Functionality

Work Management thought leader

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

PSEG

We make things work for you.

2009 go live

2.1M electric meters

1.7M gas meters

Advanced Customer Self Service

America's most reliable electric utility

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

IBERDROLA USA

2005 go live

1.6M electric meters

900,000 gas meters

SAP used as M&A synergy enablement vehicle for the consolidation of five utilities

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

Source Gas

2009 go live

420,000M gas meters

'Vehicle to realize M&A synergies'

Four State Service Territory: CO, AR, WY, UT

Why do Utilities choose SAP?
Why do Gas Utilities choose SAP?

SAP

TXU energy

2009 go live

2.1M electric meters

'Highest historical satisfaction achieved six months after SAP go live.'

Oracle SPL Replacement

Integrated Marketing

PeopleSoft Financials

Call our Customers!

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Allegheny	Michael King	Director	(724) 838.6949	MKing2@alleghenyenergy.com
Aquarion Water	Chuck Firlotte	CEO (would need to arrange call)	203.336.7628	Cfirlotte@aquarionwater.com
Bluebonnet Electric	Elizabeth Kana	CFO	(512) 332.7925	elizabeth.kana@bluebonnetelectric.coop
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CenterPoint	Shachella James	SAP IT Manager	(713) 207.5354	Shachella.james@centerPointenergy.com
CenterPoint Energy	Bill Davis	Director Financial Systems and Processes	(713) 207.8845	Bill.davis@centerpointenergy.com
City of Dallas	Karl Martin	Portfolio Manager	(214) 671-8924	karl.martin@dallascityhall.com
City of Dallas	Janet Grabinski	Project Manager	214-670-3177	janet.grabinski@dallascityhall.com
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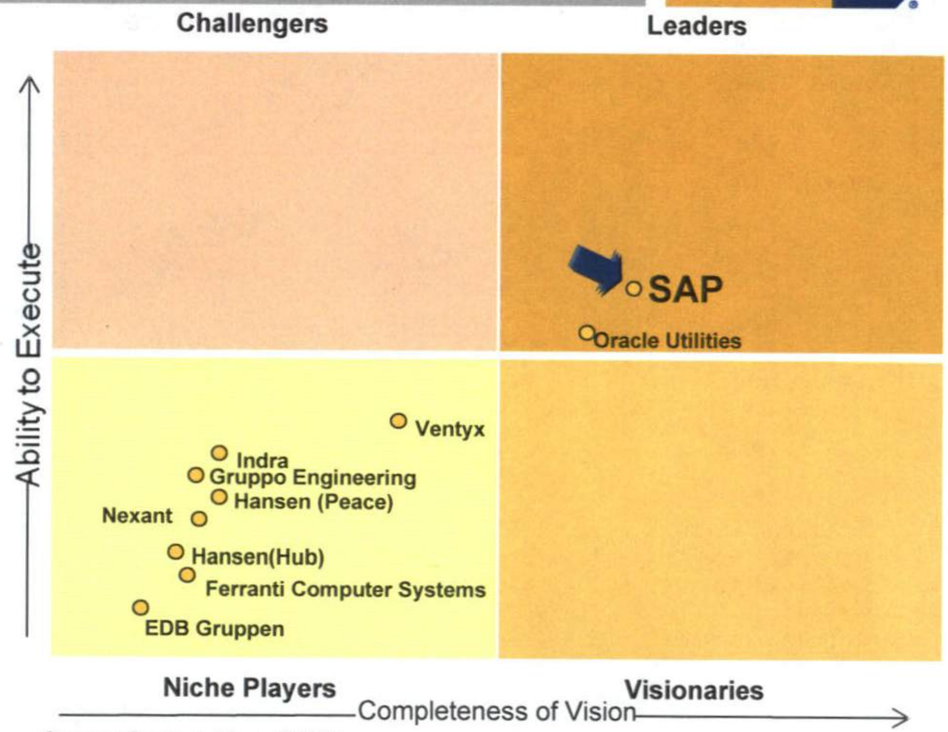
CPS	Lawanda Parnell	Sr Director, Enterprise Application Delivery	210.353.2205	LVParnell@cpsenergy.com
e.On USA	Joan Ferch	Director, Enterprise Integration	(502) 627.3655	Joan.ferch@eon-us.com
Energen	Brunson White	Chief Marketing Officer	(205) 326.1644	bwhite@energen.com
Energy East	Jeff Ballard	VP IT		Jeff.Ballard@energyeast.com
First Energy	Greg Hussing	Director Energy Deliver and Financial Systems	330-436-2140	hussingg@firstenergycorp.com
Gainesville Regional	Jennifer Hunt	CFO	(352) 393.1312	huntjl@gru.com
Huntsville	Jay Stowe	VP Operations	(256) 535.1264	Jay.Stowe@hsvutil.org
Oklahoma City Water Utility and Trust	Bret Weingart	Asst. General Manager	405-297-2828	Bret.Weingart@okc.gov
Teresen Gas	David Legge	CIO	(604) 592-7476	david.legge@terasengas.com
TXU	BJ Flowers	IT Manager	972-868-4838	BJ.flowers@txu.com
TXU	Gary Hayes	VP	972 868 4826	gary.hayes@txu.com

Selected SAP CR&B Customers

A strong focus in utilities industry

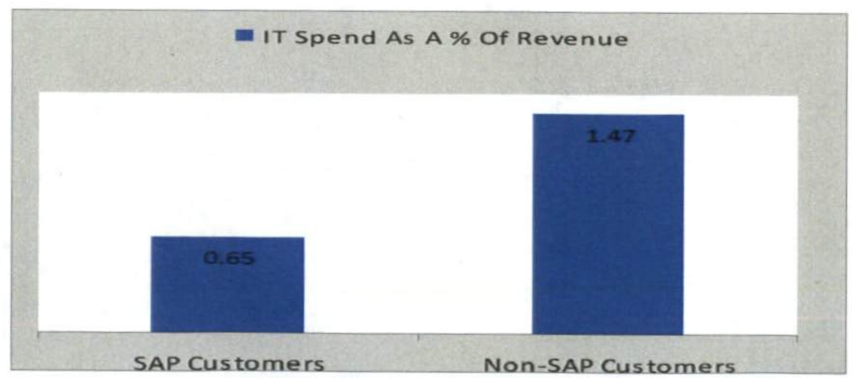
- 750+ utilities managing 2.5+ billion customer bills with SAP
- 65% CIS and 33% ERP market share (Gartner)
- Over $2B annual spend in R&D
- 12,000 employees in product development, R&D



Source Gartner (June 2009)

Comparison of Top 25 North American Utilities - KPIs			
Averages	ROA	ROE	Profit margin
Companies with SAP implementations	4.15%	14.66%	9.50%
Companies with non-SAP implementations	3.91%	10.00%	8.15%

Source : SAP Analysis; 2008/2009 data



Source : ASUG data, n=214

VI. APPENDIX B

Reference document: CIS COTS conversion study

UtiliWorks™

Synaptitude
CONSULTING

This document highlights energy utilities which have embarked on (or completed) projects to implement Commercial off-the-shelf (COTS) Customer Information Systems (CIS).

Report on Energy Utilities Customer Information Systems (CIS)

UtiliWorks™

Synaptitude CONSULTING

Report on Energy Utilities Customer Information Systems (CIS)

Introduction

This document highlights energy utilities which have embarked on (or completed) projects to implement Commercial off-the-shelf (COTS) Customer Information Systems (CIS). This is not intended to be an exhaustive list; the examples focus on Energy Utilities that are similar in attributes to the Utilities currently under review by DRA/CPUC. Note that only Energy utilities are included in this report.

This document includes:

- summary of a 2010 Market Survey on CIS Implementations
- case studies of utilities in the Americas
- case studies of utilities in EMEA
- case study of utility in Australia
- summary of COTs implementations at smaller utilities
- a list of other SAP utilities customers
- a list of other Oracle utilities customers
- a summary of the functionality provided by several Utilities COTS systems
- example of US Gas Utility utilizing COTS for CIS

Contents

Customer Information System (CIS) Market Survey Summary

A 2010 survey of 200+ North American utilities companies found that 11.5 percent of survey participants are in the market for a new CIS.

When asked about their current CIS system, the top 3 responses were:
22% legacy/in-house systems
22% Commercial off-the-shelf (COTS) systems
27% other
(the remaining 29% is not specified in the report)

There was a small increase in the number of CIS installations in 2009, possibly because of purchasing decisions made before the recession's effects were felt. The survey results indicate few installations in 2010 because of fewer purchasing decisions made in 2009.

Functionality and ease of use were the two most important purchase determination factors, followed by price. Cooperatives seem to be happiest with their current systems, with 43 percent indicating satisfaction with their current solutions. Most respondents in the Cooperatives market segment do not have legacy systems.

Source: 'Key Results From UtiliPoint's Annual CIS Market Survey"

Example Utilities in the Americas Utilizing COTS for CIS

Duke Energy
Duke Energy is third largest electric power holding company in the United States and has four million electric and gas customers in five states.

Software Provider: Convergys
Software systems/modules: Rating and Billing, Customer Management, and Collections

Project Summary: They started a project in September 2009 to implement a billing and customer management solution. Duke Energy's smart grid will incorporate automated equipment, wireless sensing devices, and advanced meters to create a digital, real-time, networked power delivery system that provides two-way communication between Duke Energy and its customers. "Duke Energy selected the Convergys Smart CIS Solution to deliver highly scalable real-time rating, dynamic billing, flexible customer and account management, and collections capabilities… based on how we are implementing the solution, this will have minimal impact on our legacy CIS infrastructure."

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Convergys - Trade Media - Jeff Hazel
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Duke Energy - Dave Scanzoni
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Source:
http://www.convergys.com/company/news-events/newsroom/news_release.php?newsid=4700

Los Angeles Department of Water & Power

Los Angeles Department of Water & Power provides electricity to 1.4 million customers in Los Angeles.

Software Provider: Oracle

Software systems/modules: Oracle Utilities Customer Care and Billing, Oracle Utilities Meter Data Management, Oracle Utilities Mobile Workforce Management and Oracle Business Intelligence for Utilities

Project Summary: In December 2010, LADWP selected Oracle to replace its legacy customer information system (CIS). The goals of the project are to enhance customer service, billing processes, field services and meter data management and support smart grid initiatives.

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Sources:
http://www.oracle.com/us/corporate/press/196423
http://www.ladwp.com/ladwp/cms/ladwp000508.jsp

The United Illuminating Company (UI)

UI is engaged in the purchase, transmission, distribution and sale of electricity and related services to 324,000 residential, commercial and industrial customers in the Greater New Haven, CT and Bridgeport, CT areas.

Software Provider: SAP

Software systems/modules: SAP Business Suite and SAP Energy Data Management

Project Summary: In 2002, UI started a project to replace their legacy systems with SAP Business Suite and SAP Energy Data Management. The legacy systems were based on a 1970's COBAL platform. They went live in 2003 and implemented enhancements in 2007. The SAP system functionality includes billing, invoicing, contract accounting and the SAP Energy Data Management application.

The United Illuminating Company integrated the new software with its mobile workforce field automation, wireless network meter reading, and interactive voice response (IVR) solutions.

Sources:
http://www.sap.com/industries/utilities/customers/index.epx
http://www.sap.com/industries/utilities/edm.epx
http://www.uinet.com/

Electric Power Board (EPB)
EPB serves 169,000+ residential electric customers in Chattanooga, TN and surrounding counties.

Software Provider: Systems & Software (owned by Harris)
Software systems/modules: enQuesta 4 Inquiry Portal, Rate Management, and Reading Edit

Project Summary: Upgraded their existing enQuesta CIS system to enQuesta 4 in 2010.

Source:
http://www.harriscomputer.com/about/PressReleases/2010-11-03_S&S_EPB.html

Westfield Gas & Electric Light Department (WGELD)
WGELD provides service to 18,000 electric and 9,000 natural gas customers in Westfield, MA.

The American Public Power Association recently honored Westfield Gas and Electric with the national distinction of a Reliable Public Power Provider, or RP3, award. WGELD's continuous focus on quality customer service with an emphasis on reliability and price has enabled the utility to provide its customers with electric rates 15% below the state average.

Software Provider: Cogsdale (owned by Harris)
Software systems/modules: Financials (FIS), Customer Service (CIS), Work Management (WMS) and CustomerWeb (customer self-service)

Project Summary: WGELD will implement a new ERP package including Financials (FIS), Customer Service (CIS) and Work Management (WMS). It will also implement CustomerWeb 2.0, Cogsdale's online customer self-service and payment solution which offers customers 24/7 access to bill presentment, numerous payment options, consumption history, ebilling and service requests.
Cogsdale was selected in October 2010.

Paul Martin, Systems Accountant at WGELD said "Customer Service is of paramount importance here at WGELD. Our selection team carefully defined our requirements for a new system and we sought feedback from our peers throughout the market on which vendor offered the most tightly integrated solution to meet all of our long term customer service goals. Upon careful evaluation of all the proposals, Cogsdale offered the most cost competitive and functionally rich solution to meets our goals of one fully integrated solution across Financials, Customer Service and Work Management"

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Source:
http://www.cogsdale.com/press_newsitemsdet.asp?id=304

Enersource Hydro Mississauga
Enersource Hydro Mississauga serves 188,000 customers in Mississauga, Ontario.

Software Provider: Oracle
Software systems/modules: Oracle Utilities Customer Care and Billing and Oracle Utilities Load Profiling and Settlement

Project Summary: Implemented Oracle Utilities Customer Care and Billing and Oracle Utilities Load Profiling and Settlement to replace their legacy systems.

Solution:
- Create billing profiles for customer care and billing, perform wholesale settlement with the Independent Electricity System Operator, and settle with generators
- Complies with new smart metering regulations, including complex time-of-use billing requirements
- Streamlined the four-step process between Enersource and the market from which it purchases power, reducing the time needed for comparison checks on billing data by 50%
- Automated the billing process for new generators that come on line, reducing manual labor costs by at least 25%
- Improved data transparency, enabling the utility to flag user issues for faster resolution and improved customer care
- Improved smart grid technologies, capturing and billing energy consumption based on interval meter reads for commercial customers, and for residential customers in the near future
- Partnered with Toronto Hydro to share costs, benefit from best practices, and more easily meet government reporting requirements

Source:
http://www.oracle.com/us/corporate/customers/enersource-hydro-uccb-snapshot-167865.pdf

The Barbados Light & Power Company Limited, provides electricity to 200,000+ customers in Barbados. They replaced a legacy CIS solution with Oracle Utilities Customer Care and Billing.

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http://www.oracle.com/us/corporate/press/018638

Duke Energy Brasil, São Paulo, Brazil, implemented Oracle Utilities Customer Care and Billing.
http://www.oracle.com/us/corporate/customers/duke-energy-brasil-uccb-snapshot-075841.pdf

Example Utilities in EMEA Utilizing COTS for CIS

E.ON

E.ON generates and distributes electricity and supplies gas to over eight million residential and business customers in the UK. E.ON is one of the UK's leading energy suppliers, the second largest electricity generator in the UK and owns the second largest distribution network in the UK.

Software Provider: Convergys
Software systems/modules: Rating and Billing Manager (revenue management software)

Project Summary: Instead of adding enhanced billing functionality into their legacy Customer Care and Billing applications, E.ON chose to keep their legacy Customer Care and Billing applications, and integrate to Convergys' Rating and Billing manager to calculate and generate cross-service utility bills.

Don Leiper, Director U.K. IT, E.ON says "...if we had not found Rating and Billing Manager then we were prepared to build our own solution. Fortunately very little additional interfacing software had to be developed in order for Rating and Billing Manager to fit into our complex systems environment.".

This project lasted 7 months and was completed in Jan 2001. The system was upgraded in 2009 to v2.2. The system supports approximately 8 million customers and processes 2.5 million accounts per month.

Source: http://www.convergys.com/pdf/BR1-082N.pdf?TRID=1

Ecotricity Group Limited

Ecotricity is a green energy provider based in Stroud, UK and specializes in wind energy. In 2007 they invested £25 million in wind energy.

Ecotricity has 4,000+ corporate customers and 40,000+ residential customers.

Software Provider: SAP
Software systems/modules: SAP CRM and SAP for Utilities

Project Summary: The company's legacy billing software was not able to support anticipated growth. They replaced the legacy system and implemented SAP CRM and SAP for Utilities. The implementation took 7 months.

Trevor Saunders, Head of Infrastructure at Ecotricity said "Because the software is developed specifically for the utilities sector, it provided the process support we needed – without us having to make extensive changes."

System Benefits:
- increased billing accuracy by 70%
- Reduced call volumes by 15% in the first month after rollout
- streamlined financial management and billing processes across the company

System Enhancements planned as of 2008:
- Allow customers to conduct transactions and receive bills online
- implement telephone self-service, web self-service, and inquiry handling by email
- implement marketing campaign management

Sources:
http://www.sap.com/industries/utilities/customers/index.epx
http://www.ecotricity.co.uk/

OnStream

Company Summary: OnStream provides gas and electricity metering solutions to energy suppliers across Great Britain. OnStream provides gas meter reading services for both domestic and non-domestic customers. To support smart metering it offers data collection and aggregation services ensuring a holistic, end-to end service for its customers.

Software Provider: Metratech
Software systems/modules: MetraNet (MetraTech's billing and customer care application)

Project Summary: OnStream selected metratech in April 2010 to provide the billing element of OnStream's extensive business transformation program.

Goals of the project:
- adapt OnStream's business model to smart meters
- enable the sales team to implement contracts tailored to customers needs
- manage complex billing contracts for the company's customers and the payments to its service providers.
- Allow customers and service providers to view and configure their bills online, providing better service and reducing the amount of queries to the company

Sources:

http://www.metratech.com/Portals/0/PDF/04-27-10-OnStream.pdf
https://www.onstream.co.uk/about/

Eesti Energia, Estonia, implemented Oracle Utilities Customer Care and Billing to replace its in-house legacy systems. Its customer base is 500,000 private and corporate customers.
Source: http://www.oracle.com/us/corporate/press/017894_EN

Bord Gáis Energy, Ireland, went live with Oracle Utilities Customer Care and Billing in May 2009. This replaced its legacy CIS. Bord Gáis Energy supplies gas and electricity to 700,000 customers in Ireland.

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Source: http://www.oracle.com/us/corporate/press/018625

Elektroprivreda Crne Gore, Montenegro, implemented Oracle Financials, Inventory Management, Purchasing, and Project Costing.
http://www.oracle.com/us/industries/utilities/024461.pdf

Example Utility in Australia

Western Power, Perth, Australia, implemented Oracle Utilities Customer Care and Billing to replace its legacy systems. The system went live in July 2009 after 8 months of analysis/design and 10 months of development/test/deployment.
http://www.oracle.com/us/corporate/customers/western-power-utilities-case-study-080403.pdf

In addition, Western Power utilizes Clarity's OSS software to manage its Grid assets, intelligent alarming, and other back-office functions. Clarity's OSS software is based on the TM Forums Frameworx model, initially created to support Telecommunications providers back-office requirements.

Smaller U.S. Utilities

The City of Sioux Falls has 2,100 electric customers in Sioux Falls, SD. They replaced their legacy billing system with CIS Infinity from Advanced (owned by Harris). The project went live in August 2010.

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Source: **http://www.harriscomputer.com/about/PressReleases/2010-08-11-AdvancedSiouxFalls.htm**

Clarksville Gas & Water Department (CGW) has 25,000 natural gas customers in Clarksville, TN.
In August 2009, they went live with enQuesta CIS which replaced their legacy system. In 2010 they implemented a new Interactive Voice Response (IVR) solution and PayConnect which provides real-time payment processing to utility customers from the convenience of their home through the Internet, IVR or Call Center payment channels.

Source: **http://www.harriscomputer.com/about/PressReleases/2010-05-25_SSI_Clarksville.htm**

City of Rocky Mount provides service to approximately 28,000 electric and 18,000 gas customers. The City of Rocky Mount began implementing a new CIS system in April 2010. They chose CIS Infinity and Infinity (a customer self-service and payment solution) from Advanced (owned by Harris).

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pfanous@advancedutility.com

Source: **http://www.harriscomputer.com/about/PressReleases/2010-03-09-AdvancedRockyMount.htm**

Central Lincoln People's Utility District provides service to 37,500 electric customers in Oregon state. They are implementing CIS Infinity from Advanced (owned by Harris) as their customer information and billing solution.

Go-live was scheduled for summer 2010.

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Source: **http://www.harriscomputer.com/about/PressReleases/2009-10-20-Advanced-CLPUD.htm**

The City of Richland provides water, wastewater, solid waste, stormwater and electric service to approximately 46,100 residents in Washington state. In Aug 2009, they went live with CIS Infinity from Advanced (owned by Harris) for billing and customer management. They replaced their legacy system.

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Melody Kendall, Accounting Operations Supervisor
City of Richland
509-942-7761
mkendall@ci.richland.wa.us

Source: **http://www.harriscomputer.com/about/PressReleases/2009-08-21-Advanced-CityofRichmond.htm**

The City of Chattanooga serves 169,000 residents in North Georgia. In Nov 2008 they chose enQuesta ERP and CIS. enQuesta is a product of Systems & Software (owned by Harris).

Source:

http://www.harriscomputer.com/about/PressReleases/2009-04-08-Situs-Chattanooga.htm

Columbia River People's Utility District (PUD) in St. Helens, Oregon provides electric service to 18,500 customers.

They implemented the Cayenta Utilities CIS product in November 2008 as well as other modules of the ERP package including billing, accounting, reporting and collections. PUD is also implementing the Cayenta Financial, Personnel and Operations Management suite of products. Those implementations were planned to be complete in 2009.

Source:

http://www.harriscomputer.com/about/PressReleases/2008-11-14-Cayenta-PUD.htm

NOVEC Energy Solutions (NES) provides natural gas to 18,000 customers in the Mid-Atlantic area. In January 2010, NES chose OpSolve LLC Customer Relationship Management (CRM) solution.

Source:

http://www.opsolve.com/news/release.php?news=2010_01_14_0

Belmont Municipal Light Department (BMLD) provides power to 11,000 electric customers in Belmont, MA. They started a project in 2009 to implement COTS software from Cogsdale (owned by Harris). The modules to be included are Financials (FIS), Customer Service (CIS), Work Management (WMS) and and Asset Management (AMS).

Contact:

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Source:

http://www.cogsdale.com/press_newsitemsdet.asp?id=256

The City of Griffin serves 26,000 customers (total including electric, water, sewage and garbage) in Griffin and Spalding County, GA.

They implemented a Cogsdale Billing System which went live in May 2010.

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Source: **http://www.cogsdale.com/press_newsitemsdet.asp?id=280**

Franklin County Public Utility District (PUD) serves 24,000 electric customers in Pasco, Washington. Franklin County PUD will utilize Cogsdale's full suite of financial management solutions, including: financial, people, asset, and work management. Chose Cogsdale in May 2009.

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Source: **http://www.cogsdale.com/press_newsitemsdet.asp?id=230**

Lewis County PUD supplies electric power to over 30,000 customers in the western heart of Washington state. Lewis County PUD will be implementing Cogsdale's full financial management suite, customer service management, and human resources and payroll. Cogsdale was chosen in March 2010.

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Source: **http://www.cogsdale.com/press_newsitemsdet.asp?id=263**

Jamestown Board of Public Utilities provides electric, water, wastewater, solid waste and district heat services to over 25,000 customers in NY state. They chose Cogsdale to replace their legacy financial, work and customer information management system. Implementation began in June 2008.

Other SAP Utility Customers

AES Sul
Allegheny Energy
Aquarion Water Company
AREVA
Bluewater Power Distribution

Casella Waste Systems
CEMIG
Conectiv Energy
Cooperativa Rural de Electrificación
Crown Technologies
E.ON Energie
Ecotricity Group Limited
Edesur
EnBW Energie Baden-Württemberg
EnBW Vertriebs- und Servicegesellschaft
Energen
Energie SaarLorLux and Stadtwerke Saarbrücken
Energinet.dk
Essent
Grupo Endesa
Light
Light Serviços de Eletricidade
Marin Municipal Water
Middle Tennessee Energy Membership Corporation
New York Power Authority
Northern Gas Networks
NTPC
PacifiCorp
PacifiCorp Business
PFALZWERKE AKTIENGESELLSCHAFT
Stadtwerke Aachen
Stadtwerke Bonn
Stedin
Südwestfalen Energie und Wasser AG (SEWAG)
Überlandwerk Fulda
Vattenfall
Wales & West Utilities
http://www.sap.com/industries/utilities/customers/index.epx

Other Oracle Utility Customers

Ameren Corporation
City of St. Petersburg Water Resources Department
Cobb Energy Management Corporation
Denver Water
GNERA ENERGÍA Y TECNOLOGÍA S.L.
npower
Pacific Gas & Electric Co.
Saur
Shanghai Municipal Electric Power Company
Yarra Valley Water

Aboitiz Power Company
Abound Solar
Abu Dhabi Water and Electricity Authority
Acea Distribuzione
Albuquerque-Bernalillo County Water Utility Authority (ABCWUA)
American Transmission Co
Aurora Energy
AVR
Baltimore Gas and Electric Company
The Barbados Light & Power Company Limited
Beijing Guohua Electric Power Co. Ltd.
Bermuda Electric Light Company Limited (BELCO)
Bord Gáis Energy
Central Hudson Gas & Electricity
Centrica Energy
Chesapeake Energy
China Yangtze Power Co., Ltd
Citelum
City of Austin
The City of Calgary
City of Clearwater
City of Las Vegas
City of Phoenix
City of Winnipeg
Companhia de Gás de São Paulo S.A. (Comgás)
DAR
Datang International Power Generation Co., Ltd
Denver Water
Edenor
Eesti Energia
Electrabel
Electricity Authority of Cyprus
Electricity Supply Board (ESB)
Electro Generadora del Austro S.A.
Empresa Baiana de Água e Saneamento S/A (EMBASA)
Empresa Eléctrica Ambato Regional Centro Norte S.A.
Energias de Portugal
EnergyAustralia
Enersource Hydro Mississauga
E.ON UK
EPCOR Utilities Inc.
Ergon Energy
Essent
Fairfield City Council of New South Wales
Golden Concord Holdings Ltd
Green Mountain Power
Hafslund ASA
Hawaiian Electric Company (HECO)

Hillsborough County Water Resource Services (HCWRS)
Hillsborough Water
Honolulu Board of Water Supply (HBWS)
Hydro One Networks
IES-Holding
Interseroh
JEA
Kansas City Board of Public Utilities
Las Vegas Valley Water District
Lyse Energi AS
Lyse Tele
Metrix
Metro Water Services
Mid-Carolina Electric Cooperative
Moalajah
Modesto Irrigation District
MSGas
National Transmission Corporation
Nevada Energy
Northern California Power Agency (NCPA)
Novi Sad Heating Plants
Nuklearna Elektrarna Krsko (NEK)
Oklahoma Gas and Electric Company
OMEL
Origin Energy
Orlando Utilities Commission
Palm Utilities
Plinacro Company
POWEO
PPL Corporation
Progress Energy
PT PAM Lyonnaise Jaya (PALYJA)
Reliance Home Comfort
RheinEnergie AG
Salt River Project
Sam Houston Electric Cooperative
San Francisco Public Utilities
San Jose Water Company
Seattle City Light
Severn Trent Plc
South Maryland Electric Cooperative
Shenhua Guohua Power Co., Ltd
Southwest Water Company
SP AusNet
Stanwell Corporation
Sui Southern Gas Company Ltd
Tianjin Electric Power Corporation
TrustPower Limited

Tucson Electric Power
United Illuminating
Utilities, Inc.
Vattenfall
Visayan Electric Company Inc. (VECO)
Western Power
Westar Energy
Yorkshire Water
http://www.oracle.com/customers/industries/energyutil.html

CIS Software Vendors - summary of the functionality provided by several Utilities COTS systems.

SAP
System functionality:
- CIS
    - Customer contact management
    - Campaign management
    - Sales management
- Billing
- ERP
- Workforce management
- Energy capital management
    - Optimize energy portfolios
    - Smart meter data integration
- Energy data management
- Financial performance management
- Asset management
- Operations management

http://www.sap.com/industries/utilities/businessprocesses/sales-marketing-service/index.epx

Oracle
System functionality:
- CIS
    - Campaign management
    - Contact center
    - Generate customer communications
- Billing
- Payment processing
- Collections
- Field Service
- Meter Data Management
- Network Management

http://www.oracle.com/us/industries/utilities/039711.htm

Systems & Software (owned by Harris)
enQuesta functionality:
- utility billing
- revenue management
- mobile workforce management
- GIS integration
- electronic bill presentment & payment (EBPP)
- automated meter integration (AMI/MDM)
- time-of-use (TOU) billing
- asset management/work management integration
- customer self-service web portal
- business intelligence
- reporting

www.ssivt.com

Cogsdale (owned by Harris)
System functionality:
- financials
- work management
- people management
- asset management
- customer information system (CIS)
- utility billing

www.cogsdale.com

Hansen Technololgies
System Functionality:
- support large-scale metering
- customer service
- billing
- revenue management
- business intelligence
- meter data solutions
  - connection point management
  - Meter data management

http://www.hsntech.com/energy/energy-solutions.aspx

cusi
System Functionality:
- Utility CIS
- Utility Billing
- GIS Solutions
- IVR

- Meter Reading
- Work Order Management
- Payment Portal

http://www.cusi.com/home/customer-map.html

OpSolve

System Functionality:

- Customer Care
- Customer Enrollment
- Contract Management
- Web Based CSR Features
- Automated Billing
- Converged Billing
- Payment Processing
- Receivables Management
- Credit and Collection
- Contact Management
- Targeted Messaging
- Letter Generation
- System Interfaces
- Data Exchange

http://www.opsolve.com/

Example of US Gas Utility Utilizing COTS for CIS

Alabama Gas Corporation (Alagasco)

Algasco provides natural gas service to nearly 500,000 customers in central and northern Alabama.

Software Provider: SAP
Software systems/modules: SAP CRM on-demand

Project Summary: The initial 3 month implementation was for a small portion of their customers. They implemented a CIS to track their 500+ large commercial customers. It's unclear whether there was a legacy system to replace.

The SAP CIS is used by Sales Reps and managers to:
- view detailed 36-month histories of gas usage by Account
- manage account and contract information and eliminate manual procedures
- track sales reps' activities
- track customer projects from start to finish
- uniform processes across 7 geographic subregions

As of July 2008, they were adding enhancements to put their 30,000+ small commercial customers on the system.

Source:
http://www.sap.com/industries/utilities/customers/index.epx

VII. APPENDIX C

Acronyms used in this testimony

Acronym	Definition
AMI	Advanced Metering Infrastructure
CIS	Customer Information System
CISCO	SDG&E Customer Information System
COTS	Custom off-the-shelf
CPP	Critical Peak Pricing
DRA	Division of Ratepayer Advocates
EBPP	Electronic bill presentment & payment
GRC	General Rate Case
IT	Information Technology
MDMS	Meter Data Management System
PSH	Peak Shift at Home
PSW	Peak Shift at Work
SDG&E	San Diego Gas and Electric
SPP	Statewide Pricing Pilot
TCO	Total Cost of Ownership
TOU	Time of Use

VIII. APPENDIX D

This document provides a list of the applications to be enhanced as part of this rate case. It also lists projects where those same applications are being enhanced as noted in the General Rate Case.

Appendix D

This appendix gives a list of the applications to be enhanced as part of this rate case. It also lists projects where those same applications are being enhanced as noted in the General Rate Case.

To implement the functionality described in this rate case, enhancements will be made to the following SDG&E IT systems (as described throughout Mr. Shulman's testimony):

- My Account
- SDG&E website (sdge.com)
- SAP Customer Relationship Management (CRM)
- possible upgrade to SAP CRM 7.0 (referenced in data request response DR-07, response 02)
- Customer Information System (CISCO)
- Operational Data Store Integration
- Meter Data Service
- the Enterprise Messaging Framework
- the Online Presentment and Rate Analysis tool
- Customer Notifications

Some of these same IT system components are also being updated in projects identified in SDG&E's General Rate Case (exhibits 15 and 18), and the AMI rate case (referenced in the SmartMeter update presentation 'SM TAP 1-18-11 Final'), including:

- SDG&E website (sdge.com) upgrade and redesign
- My Account software application upgrades
- SAP CRM application upgrade

- a new Customer Contact and Notification System
- CISCO Billing technical architecture upgrade.
- My Account online presentment (part of the AMI rate case)

SDG&E also notes, in the General Rate Case (GRC), the major changes to its IT infrastructure to support SmartMeter and other endeavors. In Mr Nichols' testimony in the GRC, on page JCN-5, it states that SmartMeter program will result in "...a transaction volume and load that is hundreds of times the capacity that SDG&E's IT infrastructure has ever had to deal with. The increase in data storage and subsequent archival requirements arising from these transactions, as well as the design constraints imposed by increasingly stringent security and privacy requirements, is unprecedented."

APPENDIX A

QUALIFICATIONS OF WITNESSES

QUALIFICATION AND PREPARED TESTIMONY

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.

Between 2005 through 2009, I worked at the Communications Division and worked on assignments related to telephone rate de-regulation (Uniform Regulatory Framework), market monitoring, and service quality issues.

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") Dynamic Pricing Application (A.10-07-009) and Pacific Gas and Electric Company's ("PG&E") 2011 GRC Phase 2 and 3 Filing (A.10-03-014).

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

A.4. I am sponsoring Chapter 1 "DRA TIME-VARIANT RATE POLICY POSITIONS" and Chapter 7 "REVENUE REQUIREMENTS AND COST ALLOCATION" of DRA's prepared testimony in SDG&E's Dynamic Pricing Filing.

QUALIFICATION 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 2--Residential Rate Design.

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

A.5. Yes, it does.

QUALIFICATION AND PREPARED TESTIMONY
OF
CHERIE CHAN

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

A.1. My name is Cherie Chan. 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 in the Electricity Pricing and Customer Programs Branch of Division of Ratepayer Advocates.

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

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I also hold a certificate in Project Management from the University of California, Extension.

I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities and ESP's as a Project Manager and Product Engineer, including SDG&E's KwickView Web Presentment portal used for the Statewide Pricing Pilot.

I joined the Commission in 2005 and have sponsored Marginal Cost and AMI Technology testimony, departing in 2007 to manage marketing and product management of smart grid programs at eMeter and Oracle. I returned to The Commission in 2009.

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

A.4. I am sponsoring Chapter 3, Small Commercial Rate Design of DRA's prepared testimony.

QUALIFICATION AND PREPARED TESTIMONY
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 as a Regulatory Analyst in the Division of Ratepayers Advocates at the California Public Utilities Commission.

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 and a Master of Public Administration from the JFK School of Government. Both degrees included coursework in finance and economics that I find relevant to this case. Since joining DRA in 1999, I have worked on revenue allocation and customer marginal costs for general rate cases, advanced meter infrastructure issues, curtailment policy, distributed generation, congestion pricing and undergrounding issues (regarding distribution wires) prior to working on this case. 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 Chapter 4 on the proposal benefit analysis and Chapter 6 on facilities and operations costs.

Q.5. Does this complete your testimony?
A.5. Yes, it does.

QUALIFICATION AND PREPARED TESTIMONY

OF

DALE PENNINGTON

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

A.1. My name is Dale Pennington. My business address is 8000 GSRI Ave., LBTC Bldg., Suite 245. Baton Rouge, LA 70820.

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

A.2. I am employed by Utiliworks Consulting, LLC as the Managing Director. I am working under the authority of the California Public Utilities Commission as an expert witness in the SDG&E Dynamic Pricing Proceedings.

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

A.3. My expertise is developing AMI and Smart Grid solution architecture to drive business improvement for utilities. I have extensive knowledge of the technology, software and networking components that are utilized in the AMI market. By utilizing proven workflow and asset management techniques that I have practiced over the last 20 years, I am able to assist clients in maximizing the benefits of their AMI technology investment. My educational background is as follows:

- MS, Geophysics; Adelphi University; 1982
- BS degrees, Marine Science and Political Science; Long Island University, 1978
- BA degrees, Geology and American Studies; Long Island University, 1978

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

A.4. As the expert witness, my responsibility has been to provide a technical analysis of SDG&E’s proposal, including costs, and testimony for this case. Additionally, I have assessed SDG&E's existing IT systems and made recommendations on SDG&E's proposed methodology to implement dynamic pricing. My responsibility in this case has also been in the following areas:

- Assess and make recommendations based on the proposed upgrades to SDG&E's customer-assistance website to determine if these upgrades will carry out the desired functionality or not.
- Evaluate and make recommendations on SDG&E’s customer outreach, education, marketing plans are likely to be effective.
- Determine reasonable costs associated with the above-mentioned functions -- IT investments, outreach, education, and marketing costs

QUALIFICATION AND PREPARED TESTIMONY
OF
ERIC NELSON

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

A.1. My name is Eric Nelson. My business address is 8300 Boone Blvd, Suite 500, Vienna, VA 22182.

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

A.2. I am a Managing Principal of Synaptitude Consulting. I am representing the Division of Ratepayer Advocates ("DRA") in this proceeding.

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

A.3. I received a Bachelor of Arts degree in Political Science from George Washington University in 1982. I have written testimony for various Public Utility Commissions. I have never testified before the California Public Utilities Commission.

I have 30 years of Information Technology experience, including over 10 years as a Chief Information Officer (CIO). I am a recognized leader in large-scale back-office operations (e.g., ERP, data warehouse, event collection and management, outage management and monitoring, et. al.) and front-office customer-facing (e.g., very complex Billing and Customer Care, web portals, decision analysis, business intelligence, data analytics, et. al.) IT systems; having published several papers/presentations on this subject, presenting on this subject at over 15 conferences and events, contributing to several magazine articles and interviews, and architecting and implementing these kind of systems for over 15 years of my 30-year IT career.

I am currently a Managing Principal with Synaptitude Consulting, providing Transformational Enterprise and Back-Office Systems Consulting, with offices in DC, NYC, and Seoul, Korea. I was formerly the Managing Principal with Alteritech, an IT Infrastructure and Managed

Services firm located in the Washington DC area. Prior to Alteritech I was SVP and CIO for next-generation communication service providers MegaPath Networks and Netifice Communications. I previously held two executive management positions with e.Spire Communications, including head of ACSI NT Network Technology Solutions Division and VP of Strategic Systems.

In addition, I have worked for Bell Atlantic and MFS Communications leading divisions in their Information Systems organizations. I have also worked with several management consulting companies including The Management Network Group (TMNG), Cap Gemini Sogeti, and Ernst and Young.

In addition to my BA from George Washington University, I have completed several Executive Management programs at Wharton Business School and other post-graduate institutions. I speak at several industry conferences and events during the year, and I serve in advisory and consulting roles on several corporate and industry boards, including:

Board of Directors, Glen Echo Park Partnership for Arts and Culture
Member, Gerson Lehrman Group Council of Communications Advisors
Member, Vista Research Advisors
Member, Dematteo Moness Advisors
Member, NetEconomy Service Provider Panel
Member, META Group Technology Research Forum
Member, Primary Global Research Technology Advisors
Member, eWeek Advisory Panel
Nominated, Computerworld Premier 100 IT Leaders

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

A.4. I am sponsoring Chapter 5 of DRA’s prepared testimony.

Q.5. Does this complete your testimony?

A.5. Yes, it does.

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that I have this day served a copy of the foregoing document "**TESTIMONY ON SAN DIEGO GAS AND ELECTRIC'S DYNAMIC PRICING APPLICATION**" in **A.10-07-009** was served as follows:

[x] **BY E-MAIL**: I sent a true copy via e-mail to all known parties of record who have provided e-mail addresses.

[ ] **BY MAIL**: I sent a true copy via first-class mail to all known parties of record.

Executed in San Francisco, California, on the 18th day of February, 2011.

/s/ MARGARITA LEZCANO

MARGARITA LEZCANO

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A.10-07-009

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