**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2011. (U 39 M)	**Application No. 09-12-020 (Filed December 21, 2009)**

**ERRATA REVISON #3 TO
ANALYSIS OF HISTORICAND PROPOSED RATE STRUCTURE BY WZI, INC., ON BEHALF OF THE KERN COUNTY TAXPAYERS ASSOCIATION REGARDING THE GENERAL RATE CASE APPLICATION OF TNE PACIFIC GAS AND ELECTRIC COMPANY**

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November 16, 2010
Third revision

A.09-12-020
Michael Peevey, Commissioner
David K. Fukutome, Administrative Law Judge

Errata

Cover page
Date should included “Revision 3” to reflect errata

Page 18
Revisions to Table 5 reflect corrections made to the summer Basic Electric Tier 3 increment. Table 5 should be revised to read:

Residential										
ELECTRIC										
Baseline Territories and Quantities										
Effective May 1, 2008 - Present										
	Winter					Summer				
	(Effective November 1, 2008)									
TERRITORY	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
ALL-ELEC.										
(Code H)	Daily					Daily				
P	35.5	10.7	21.3	35.5	35.5	20.1	6.0	12.1	20.1	20.1
Q	22.9	06.9	13.7	22.9	22.9	11.1	3.3	6.7	11.1	11.1
R	32.6	09.8	19.6	32.6	32.6	23.2	7.0	13.9	23.2	23.2
S	32.0	09.6	19.2	32.0	32.0	20.1	6.0	12.1	20.1	20.1
T	20.2	06.1	12.1	20.2	20.2	11.1	3.3	6.7	11.1	11.1
V	27.5	08.3	16.5	27.5	27.5	16.5	5.0	9.9	16.5	16.5
W	29.2	08.8	17.5	29.2	29.2	27.3	8.2	16.4	27.3	27.3
X	22.9	06.9	13.7	22.9	22.9	12.2	3.7	7.3	12.2	12.2
Y	30.9	09.3	18.5	30.9	30.9	15.0	4.5	9.0	15.0	15.0
Z	31.5	09.5	18.9	31.5	31.5	12.8	3.8	7.7	12.8	12.8
Avg	28.5					16.9				
BASIC ELEC.										
(Code B)										
P	12.9	3.87	7.74	12.90	12.90	16.5	5.0	9.9	16.5	16.5
Q	12.6	3.78	7.56	12.60	12.60	8.3	2.5	5.0	8.3	8.3
R	12.3	3.69	7.38	12.30	12.30	18.1	5.4	10.9	18.1	18.1
S	12.7	3.81	7.62	12.70	12.70	16.5	5.0	9.9	16.5	16.5
T	9.8	2.94	5.88	9.80	9.80	8.3	2.5	5.0	8.3	8.3
V	11.1	3.33	6.66	11.10	11.10	9.6	2.9	5.8	9.6	9.6
W	11.4	3.42	6.84	11.40	11.40	19.4	5.8	11.6	19.4	19.4
X	12.6	3.78	7.56	12.60	12.60	12.1	3.6	7.3	12.1	12.1
Y	13.3	3.99	7.98	13.30	13.30	12.2	3.7	7.3	12.2	12.2
Z	11.6	3.48	6.96	11.60	11.60	8.8	2.6	5.3	8.8	8.8
Avg	11.7					13.0				

Page 19
Revisions to Table 6 reflect corrections made to the summer Basic Electric Tier 3 increment. Table 6 should be revised to read:

Climate Region	Summer All Electric Tier-Based Consumption				
	1	2	3	4	5
Q	11.1	3.33	6.66	11.1	11.1
W	27.3	8.19	16.38	27.3	27.3
Ratio	2.459459	2.459459	2.459459	2.459459	2.459459
	Summer Basic Electric Tier-Based				
	1	2	3	4	5
Q	8.3	2.49	4.98	8.3	8.3
W	19.4	5.82	11.64	19.4	19.4
Ratio	2.337349	2.337349	2.337349	2.337349	2.337349

Pages 23 and 24
Revised Tables 11through 14. Tables have been revised to correct Tier 3 rate allocations to residuals.

Tables 11 through 14

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	5.82	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
70	kWh	50.6	44.78	38.96	19.56	0.16	
Rate	¢/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$2.30	$0.79	$1.60	$7.87	$0.08	-
30 days	$	$69.12	$23.57	$48.14	$236.16	$2.27	$379.27

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	25%	20%
kWh/d	70	35	31.5	28	24.5	18	17.5
Est. Monthly Bill	$ 379.27	$ 234.09	$ 184.33	$ 138.41	$ 95.80	$60.26	$36.35

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	5.82	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
100	kWh	80.6	74.78	68.96	49.56	30.16	
Rate	¢/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$2.30	$0.79	$1.60	$7.87	$14.29	-
30 days	$	$69.12	$23.57	$48.14	$236.16	$428.81	$805.81

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	25%	20%
kWh/d	100	50	45	40	35	25	25
Est. Monthly Bill	$ 805.81	$ 447.36	$ 376.27	$ 305.18	$ 234.09	$101.89	$60.26

Should read

Table 1

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	11.64	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
70	kWh	70	50.6	44.78	33.14	13.74	0
Increment		19.4	5.82	11.64	19.4	19.4	0
Residual		19.4	5.82	11.64	19.4	13.74	
Rate	$/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$ 2.30	$ 0.79	$ 3.21	$ 7.87	$ 6.51	
30 days	$	$ 69.12	$ 23.57	$ 96.28	$ 236.16	$ 195.35	$620.49

Table 2

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	30%	25%
kWh/d	70	35	31.5	28	24.5	21	17.5
Est. Monthly Bill	$ 620.49	$ 337.29	$ 287.53	$ 237.77	$ 188.00	$144.52	$101.91
Avg. Price ($/kWh)	0.295472	0.321229	0.304262	0.283054	0.255786	0.229393	0.194118

Table 3

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	11.64	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
100	kWh	100	80.6	74.78	63.14	43.74	
Increment		19.4	5.82	11.64	19.4	19.4	
Residual		19.4	5.82	11.64	19.4	43.74	
Rate	$/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$ 2.30	$ 0.79	$ 3.21	$ 7.87	$ 20.73	
30 days	$	$ 69.12	$ 23.57	$ 96.28	$ 236.16	$ 621.89	$1,047.03

Table 4

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	30%	25%
kWh/d	100	50	45	40	35	30	25
Est. Monthly Bill	$1,047.03	$ 550.56	$ 479.47	$ 408.38	$ 337.29	$266.20	$195.11
Avg. Price ($/kWh)	0.3490097	0.367039	0.355163	0.340317	0.321229	0.295779	0.260149

WZI INC.

Analysis of Historic and Proposed Rate Structure

October 2010
Revision 3

Submitted to:
Kern County Taxpayers Association
331 Truxtun Avenue
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Prepared by:
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1 Introduction

WZI is a closely held woman-owned energy and environmental consulting firm located in Bakersfield, California. We have provided energy consulting to fortune 500 companies, licensing support for power generation and energy studies for industrial consumers.

I graduated from Rose-Hulman Institute of Technology in 1981 with a B.S. in Chemical Engineering. From that time I have been directly involved in electrical generation and energy. As a former employee of both Power Systems Engineering and Destec Energy, I functioned in the regulatory affairs department. I supported the legal department on matters before ratemaking bodies and gave testimony related to externalities. I have provided energy studies, developed numerous project specific energy proformas and negotiated PPAs, off-take agreements, and financial transactions. I have provided expert witness testimony on energy related valuations. In this instance KERNTAX has tasked me with analyzing certain elements of the General Rate Case Phase 2 herein referred to as "GRC P-2". My CV and work documents are available on request

KERNTAX requested that:

- WZI provide a review in response to intervener claims that certain regulatory requirements have been in place for a substantial period of time.
- WZI review the arguments proposed by various interveners to determine the veracity of their claims of equitability and fairness.
- WZI review the regional impacts of tiers.

2 Historic Evolution of Tiered Rates

2.1 Regulatory and Historic Context

2.1.1 Prior to PURPA

Prior to the Public Utility Regulatory Policies Act of 1978 (PURPA), utility ratemaking largely consisted of bundled pricing controlled entirely by the host utility and the Public Utility Commission (PUC). Retail prices were driven by "Need Conformity," and approved costs considered in the context of prudency and avoided costs which were applied to the ratebase using an Equal Percentage of Marginal Cost (EPMC) formulation.

Pricing models relied on a combination of short run and long run marginal costs adjusted for various allocation factors such as peak and off-peak. Typically long run costs were more practical since the calculation did not require any time of use capability.

Metering was strictly tied to a bundled bill that was typically adjusted for fuel costs. After PURPA, and prior to the mid-1990's deregulation/restructuring of the electricity system, energy deliveries to customers of any class were largely priced as a bundled cost consisting of:

- the average variable cost to generate the energy (which included variable costs such as O&M)
- a capacity cost (to cover the cost of capital such as construction debt)
- a surcharge (to cover T&D).

Pricing was a simple matter of demand and voltage level-of-service, and a totalized value of energy tied to the short-run avoided cost (SRAC) plus a distribution and demand charge spread out across sectoral users as some form of Equal Percentage of Marginal Cost (EPMC). To build new generating units, independent power producers contracted for capacity payments which varied by the busbar voltage, the type of dispatch; baseload, as-available, peaker, etc. California toyed with some tiered ratemaking after the 1974 energy crisis but did not venture anywhere near the current tiered framework until the recent five years.

The figure below is based on the PG&E published historic rate schedules. Note the rapid break between 2005 and 2006 tying to the same period that ExecutiveOrderS-3-05was enacted and AB 32 was passed, indicating a strong shift from a cost-of-service philosophy to a social program based philosophy.

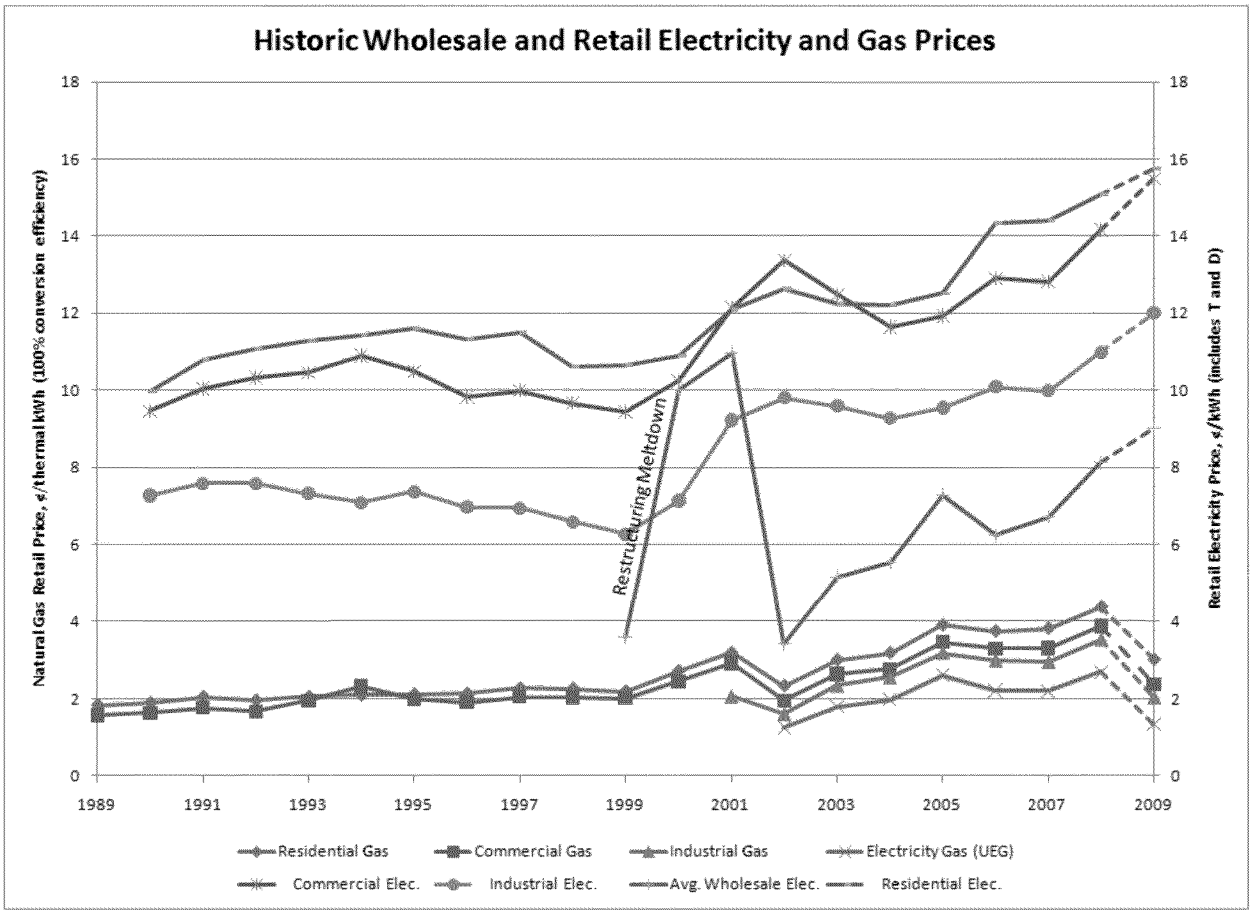

Figure 2-1

Ratemaking was defined for the US by the philosophical economic contribution by Hotelling (1938). Hotelling advocated a sea change from the prior philosophy of letting the "beneficiaries bear the burden" to a concept where competitive prices were favored over social-value in ratemaking. The belief being that the competitive price system was more efficient.

Rate making become more refined and by 1974 the Wisconsin PSC ruled to create a formula for determining the estimated marginal costs in what is known as the Madison Gas and Electric case.

> *"Madison Electric stands for four basic propositions: (1) the desirability of long-run incremental cost pricing (LRIC), (2) the importance of flattening rates (and decreasing quantity discounts) in circumstances of diminishing economies of scale, (3) the possibility of reflecting externalities in rate design, but the preferability of addressing this problem through taxation, and (4) the usefulness of peak-load pricing as*

*the ultimate outcome of cost-based pricing principles, and in particular, pricing based on LRIC. The case also notes the need for recognition of equitable and other non-economic considerations in ratemaking."*Cudahy and Malko (1976, p78)"[1]

2.1.2 PURPA

With the advent of PURPA in 1978 FERC recognized that time-of-use rate making could postpone plant additions and shift output to more efficient baseload facilities. PURPA encouraged states to use TOU and not use block rates.

Block rates have become increasingly important in California after AB 1890 proved unsuccessful. The figure below is based on the historic PG&E rates in place as of September of the given year.

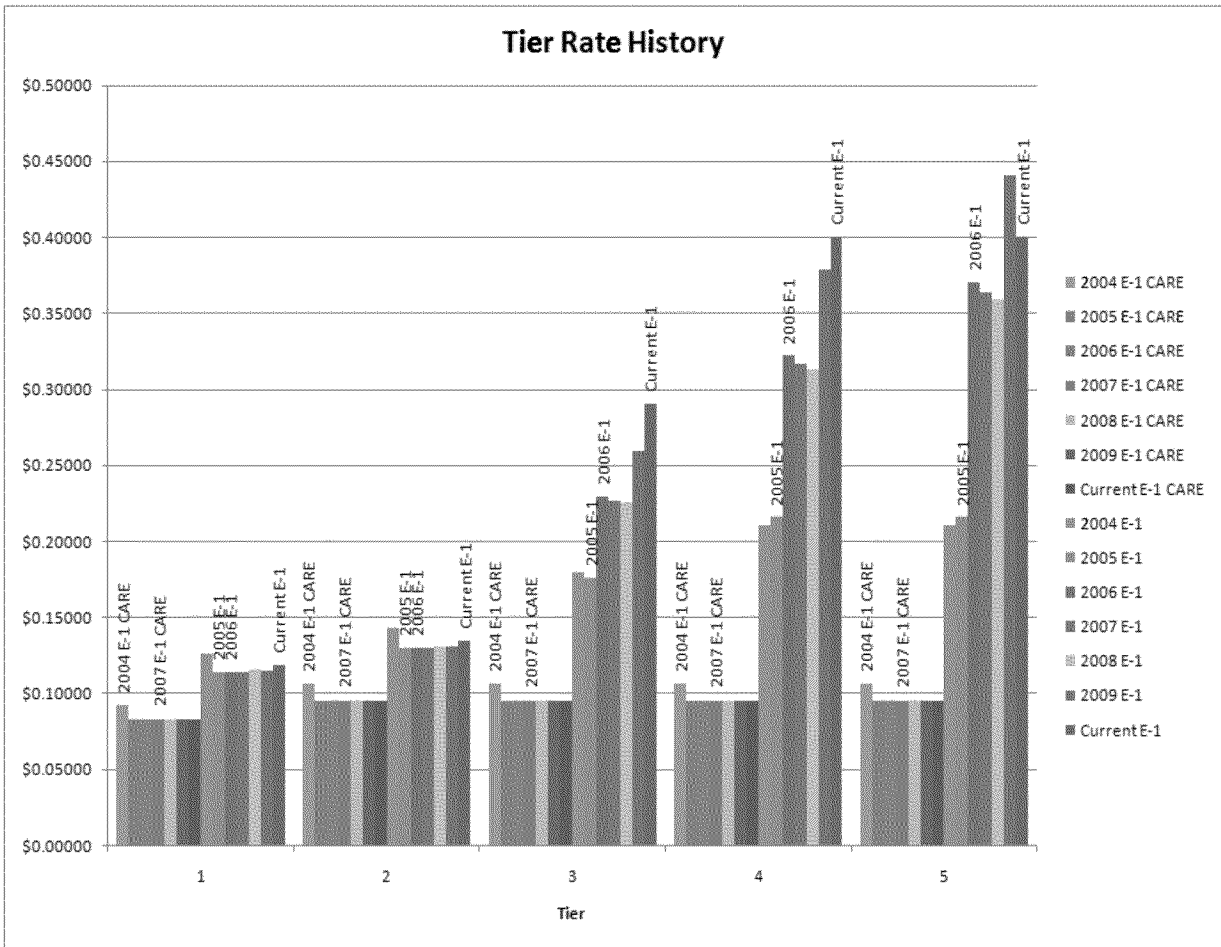

Figure 2-2

[1] Bonbright, *Principles of Public Utility Rates.*,

The figure below shows data gathered from EIA and California Power Exchange. [2] The figure underscores the post AB 32 distortion in wholesale rates and more importantly the departure of rates from the historic correlation between natural gas prices (converted to ¢/kWh thermal) and electricity rates.

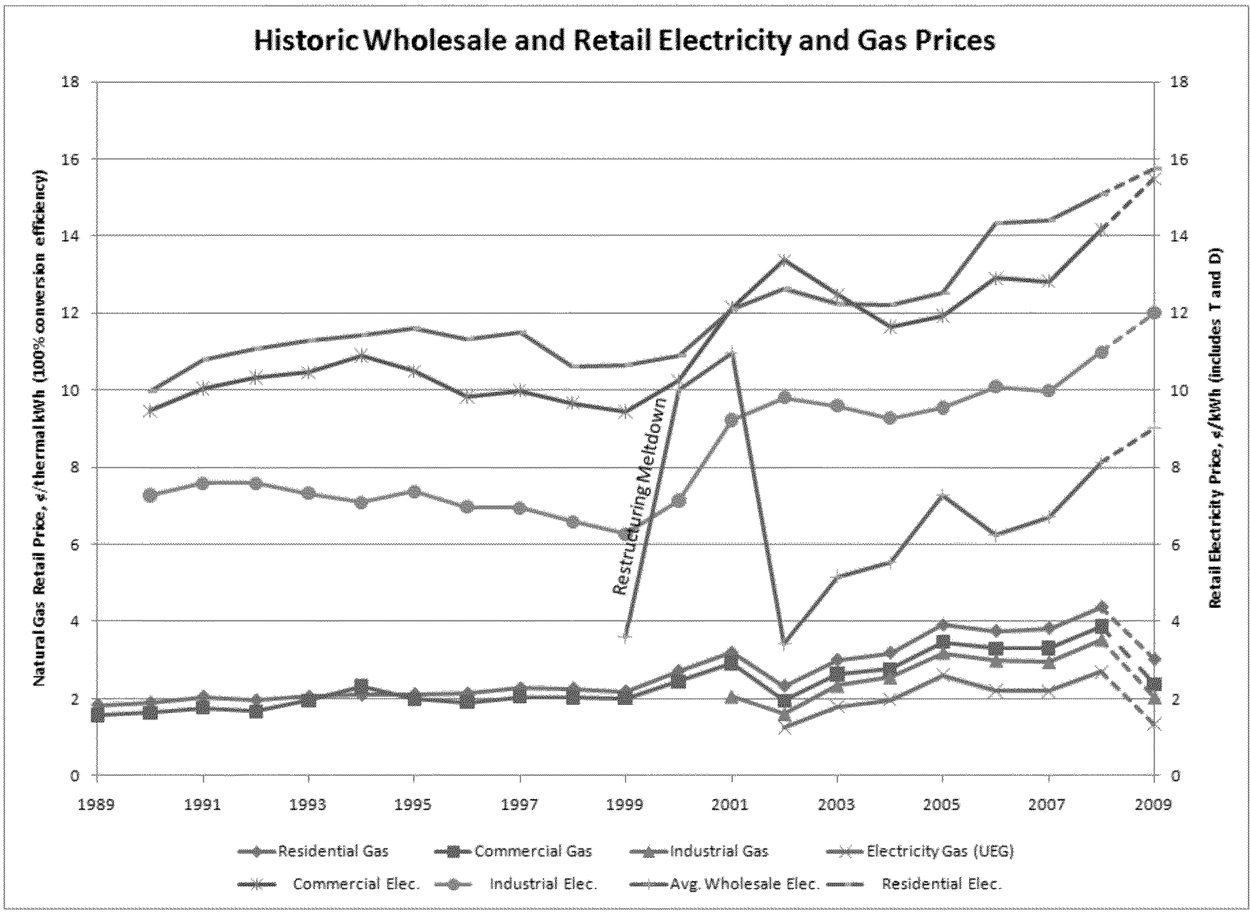

Figure 2-3

Historically, on-grid, supplemental electrical energy (i.e., from non-utility owned generators) was paid for based on SRAC mechanisms that typically reflected the system average heat rate and the commodity price of fuel (a system-wide spark spread). Financial risk was largely fuel-based and project financiers pressed domestic developers to find risk hedges for fuel only. Up to this time residential rates were reasonably correlated to energy costs.

2.1.3 AB 1890

By 1996, California's AB 1890 established a scheme for energy procurement that relied on the Power Exchange (PX) and the California Independent System Operator (CAISO) to set commodity prices in a bid framework consisting of energy prices and ancillary services prices.

[2] Data processed as part of a paper "GHG REGULATION FOSSIL-FIRED MARGINAL-COST IMPACTS: A DEMAND DURATION-BASED ANALYSIS", by Frederick, 2009 to 2010

(Real-time pricing was beginning to emerge at the wholesale level.) The outcome of this approach was to create a new level of risk that previously had been mitigated through the long-run avoided cost-based (LRAC) power purchase agreements. Proforma components (such as capacity payments), which were once tied to a long-term contract (10 years+) that covered fixed costs, now became a consideration of several hourly-based bid elements. Risk management moved to a more complex combination of capital risk, as well as off-take and fuel supply. Generators that were bidding into the PX now included an hourly premium to cover the capacity risk; this capacity recovery became one of the major upward pressures in the bid market.[3]

The figure below shows the pre AB 1890 load/demand duration as a function of demand mapped as a percentage of total time on the right vertical axis and MCP on the left for the same demand. The Average Variable Cost (AVC) and Fossil Supply Curves were effectively held to less than $20/MWh (2¢/kWh) to serve the statewide baseload demand duration (0 to 17GW) through long-term contracts and PUC-regulated utility ownership.

The pre-electrical restructuring, all-in average energy price (average variable cost) held steadily to about 3¢/kWh over the entire dispatch. Note that the stepwise changes in this stylized fossil-fired dispatch reflect certain types of incremental demand of major facilities that one might expect to see in modeling large facility demand and dispatch.

[3] "The Electric Utility Industry Restructuring Act" (Assembly Bill 1890) of 1996: This bill was originally promoted as a cost-neutral program which like many regulatory schemes seems too good to be true. A $7 billion bond was intended to fund a 10% rate reduction and the $28 billion owed to the utilities for stranded assets would be paid by the difference between cheaper energy and the frozen rates through the Competitive Transition Charge. The program was promoted as one that would ultimately reduce the cost of energy to end users (possibly below the price necessary to sustain capital and operational costs for new construction). Some experts warned that the market mechanisms could become unstable. Believing that the market would be cooperative in resolving any instability, the CPUC pressed forward with their design (CPUC Decisions 95-12-063 and 96-03-022). The impact of poor market management led to inordinate prices for energy that exceeded the state's capacity and willingness to pay. A 20/20 perspective shows us that the California restructuring program, which was a shambles by 2001, left a legacy of problems due to poor planning and late execution. By 2003, El Paso Electric Company settled for $15.5 million for supposed collusion with Enron, the Ninth U.S. Circuit Court of Appeals denied the State of California's challenge to Pacific Gas & Electric Company's post-bankruptcy reorganization plan, and the Federal Energy Regulatory Commission (FERC) upheld long-term power pacts between California and electricity merchants removing any notion that the contracts could be renegotiated.

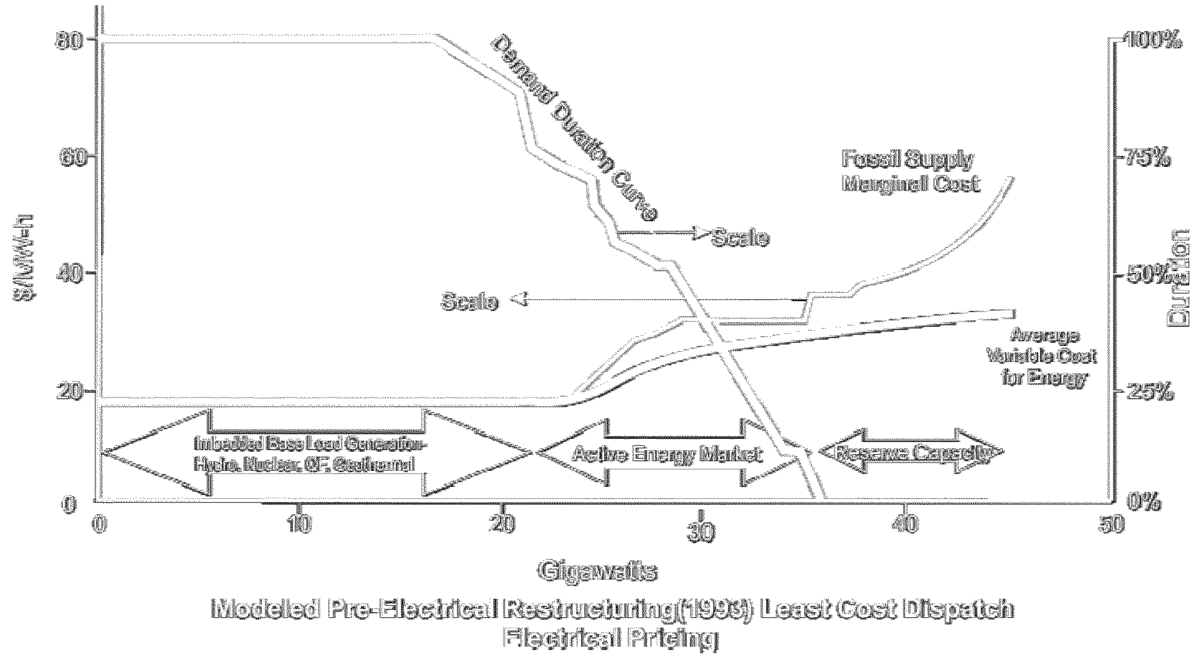

Figure 2-4

The figure below shows the Uniform Market Clearing Price under AB 1890 as recorded by the Power Exchange prior to its demise.

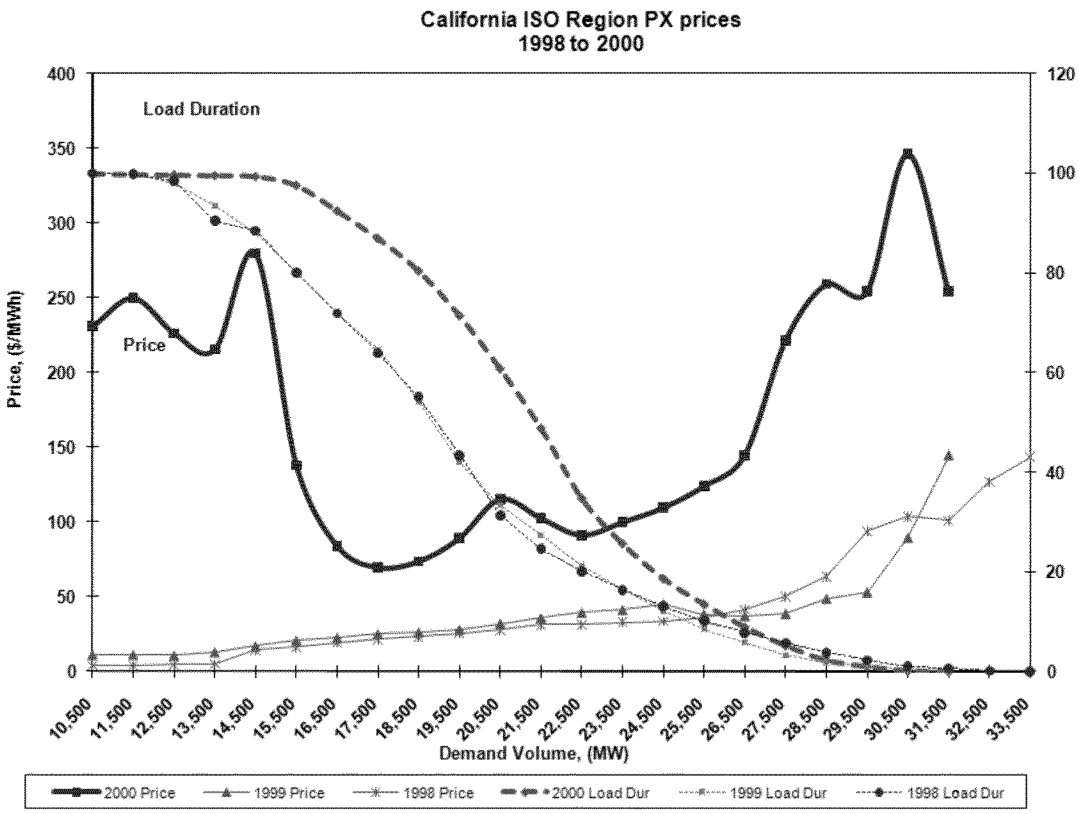

Figure 2-5

During this period, retail costs were still largely bundled, with the exception of the direct access (DA) customers. DA customers basically agreed to bear the risk and market price for energy, and to pay the necessary tariffs to seek an alternate source for their energy needs. Hedge markets emerged as quickly as contracts could be written, and hedge companies developed dynamic business models to identify and calculate risk and the costs for mitigation. Derivatives became a heavily relied upon financial instrument, and deregulation of the financial institutions left the SEC unable to provide meaningful oversight of the energy-related derivatives market.

In 2000, California utilities reached a crisis state when rate-freeze and market prices (green curve) departed from the economic model upon which AB 1890 implementation relied. The 1999/2000 liquidity crunch and ensuing collapse of the energy markets forced PG&E into bankruptcy and ultimately threw Enron in the crossfire of a series of calls that exposed their poor liquidity and highly questionable business and accounting practices.

2.1.4 AB 1X

In California, the post-AB 1890 meltdown prompted emergency legislation (AB 1X), to enable the California Public Utility Commission (CPUC) to recover the out-of-market emergency purchases by DWR and guarantee that any obligations related to electricity costs were not borne by any agency or utility but passed directly to the ratepayer, clearing the way to install interval metering and to ultimately create complex, multi-tiered electrical pricing structures.

As a result of the creative structures related to AB 1890 the concept of useable headspace became an acceptable practice. The head space between the rate freeze and the Competitive Transition Charge was considered by stakeholders as a utility cash cow. This notion seems to have continued after the restructuring meltdown. Under AB 1X the head space created by higher tier rates is intended to fill in the tier 1 and tier 2 subsidies and pay for social programs. The "headspace" left by the retiring repayment schedules of the rate reduction bonds (related to the rate freeze) of AB 1890 rate freeze bonds was viewed as an "in place" funding mechanism to start California's Solar Initiative (CSI).

> *"We ... believe that these funding levels, on average, will not result in rate increases for most customers. This is chiefly because the Rate Reduction Bonds authorized in AB 1890 in 1996 (California's Electric Restructuring Law) are due to expire at the end of 2007, which will leave additional headroom in utility rates to allow the CSI to be funded without the need for substantial additional rate increases.* (Excerpt from a CPUC Joint Staff proposal to implement CSI.) [4]

This use of retiring accounts was not publically contemplated in the development of AB 1X and rate reductions that should have occurred never materialized.

Under the post-restructuring and AB 1X framework, energy metering now reflects a tiered-use arrangement that includes a complex mixture of existing asset generation costs, public policy objective costs, subsidized renewable energy and capital, hourly fossil-fired Market Pricing (which still includes some imbedded capacity expectations), and a sliding scale charge for

[4] CPUC D0601024 Appendix A. See <http://docs.cpuc.ca/gov/published/FINAL_DECISION/52898.htm.

Transmission and Distribution (T&D) ultimately dovetails, after-the-fact, into tier pricing that has no relationship to actual dynamic demand/load following.

2.1.5 Liquidity Shift as a Result of PG&E's Bankruptcy

Contrary to public perception, the California energy liquidity crisis was not due to some massive business led manipulation. It was due to the combination of a rate freeze coupled with convoluted market mechanisms and capital adjustments instruments. In that instance the systemic failures manifested themselves as the financial implosion of the Power Exchange and the bankruptcy of PG&E due to the resultant to collect sufficient monies from ratepayers to cover the real time wholesale energy costs.

Currently, the same parties wish to avoid the problems of another liquidity crunch by passing the exposure directly to the ratepayer. Enron led us on a path that masked the failure of AB 1890. Instead of closing the door to poor ratemaking practices, the pursuit of Enron left us believing that policymaking had been a success and that the only failure was market management or policing of fraud.

Tier related pricing coupled with the liquidity shift has moved the cost impacts directly on to certain social classes and subgroups of users, not necessarily based on discretionary consumption of energy or impact to real time demand.

Like the Enron case, the effort by some to indict the Smart Meter has also wasted valuable time while the meters were tested once again to ensure veracity.

2.1.6 AB 32

No ratemaking history should ignore the current and future impact of AB 32 and related regulation. On September 27, 2006, Governor Schwarzenegger signed into law AB 32, "The California Global Warming Solutions Act of 2006." This legislation required ARB to adopt a GHG emissions cap on all major sources in California, including the electricity and natural gas sectors, to reduce statewide emissions of GHGs to 1990 levels.

The next paradigm is one where GHG must be managed in the same dynamic framework wherein the ratepayer is exposed to the GHG regulation driven market-based pricing structure that is directly tied to control area demand.

Regulatory and utility-pricing programs being developed will now incorporate the impact of the Renewable Portfolio Standard, the reduction of in-state fossil-fired units, Cap and Trade impacts and fewer fossil-fired imports. California is pressing aggressively toward a Smart-Meter future that will create an even more complex set of rules that will transform otherwise oblivious customers into active risk participants regardless of social class, service territory or climate region.

3 Analysis of Potential Causes of Variation in Tiered Rates by Climate Regions

In order to assess the efficacy of the premise that the tiers are discriminatory one should consider the body of comparative analysis between models and actual rates and consumption. One such example is titled, "A COMPARISON OF PER CAPITA ELECTRICITY CONSUMPTION IN THE UNITED STATES AND CALIFORNIA, CEC-200-2009-015, August 2008

> *"In this study, heating and cooling load, electric water heating, household income and size, and urban-rural distributions accounted for a reduction of more than 2000 kWh/person/year from the U.S. average. A portion of the unexplained reduction of 594 kWh/person can be ascribed to energy efficiency, and building and appliance standards in the state. Bernstein et al apply a panel regression where the state effect coefficients and the residuals represent partial attribution to energy efficiency and state policies. Here, average household size, disposable income, employment, electricity and gas prices, CDD and HDD are used to model changes in residential energy intensity. California was shown to have the largest reduction in residential energy intensity from 1988 to 1999. It was also shown to have favorable characteristics such as milder weather, larger household size, and high energy prices providing an additional contribution to the decreased residential energy intensity.*
>
> *One of the most striking differences between California and the average United States is the milder California climate. Between 1990 and 2005, California had 2460 average annual heating degree days (HDD) and 941 cooling degree days (CDDs) while the U.S. had 5181 HDDs and 1133 CDDs. Another significant difference in California is the average household size. Since 1980, California has seen an increase in household size while the U.S. has seen a decline. In 2005, California had around 2.8 persons per household and the U.S. had 2.6. California also has a higher concentration of urban areas – resulting in a higher number of multi-family housing units. All of these characteristic help to lower the per capita residential energy use in California relative to the U.S.*
>
> …
>
> *Taken from the Bureau of Economic Analysis, average income has a small positive impact on electricity use per capita: $1000 more a year corresponds to an increase of 40 kWh, almost 1% of the 4329 kWh per capita average.* ***Hot weather (CDD) as reported in Global Energy's Velocity Suite database increases electricity use substantially; cold weather (HDD from the same database) has an insignificant effect.*** *As the negative correlation between CDD and HDD variables is high (-.85), the regression results cannot perfectly distinguish their effects - making the HDD coefficient's confidence intervals cross zero.*
>
> …

> *A one cent per kWh rise in electricity price corresponds to a 174 kWh drop in electricity use, 4% of average usage."*[5] *[**emph**]*

3.1 Socio Economics

As requested by KERNTAX, WZI reviewed the basic socio economic conditions of those counties served by PG&E. Several were excluded either due to lack of data or were determined to be largely served by non-PG&E service providers such as SMUD, IID, etc. The table below summarizes the county wide data which has been sorted in descending order based on per capita income.

[5] CEC, "A COMPARISON OF PER CAPITA ELECTRICITY CONSUMPTION IN THE UNITED STATES AND CALIFORNIA, CEC-200-2009-015, August 2008

Table 1

COUNTY	Average Household	Average Income	Annual 2008 GWh/HH	2008 Population
Alameda County	2.75	$70,079	3051.1216	1,543,000
Amador County	2.32	$56,258	146.60653	37,943
Butte County	2.49	$41,569	737.05433	220,407
Calaveras County	2.56	$57,703	204.28173	46,127
Colusa County	2.86	$50,288	65.514438	21,910
Contra Costa County	2.76	$78,619	2838.9167	1,051,674
Del Norte County	2.65	$35,861	135.97272	29,419
El Dorado County	2.67	$70,022	783.03413	179,722
Fresno County	3.14	$45,805	2600.9891	931,098
Glenn County	2.95	$40,284	93.821241	29,195
Humboldt County	2.37	$40,515	449.10744	132,821
Imperial County	3.27	$37,492	486.35416	176,158
Kern County	3.1	$46,442	2180.1724	817,517
Kings County	3.25	$49,419	361.9858	154,434
Lake County	2.58	$41,619	290.18606	64,059
Lassen County	2.34	$50,077	106.72734	35,757
Madera County	3.23	$45,646	715.21191	150,887
Marin County	2.36	$88,101	343.93028	257,406
Mendocino County	2.51	$43,307	679.34752	90,163
Merced County	3.3	$44,338	745.75375	255,250
Monterey County	3.1	$59,140	384.64962	428,549
Napa County	2.63	$67,484	426.45793	136,704
Nevada County	2.39	$56,890	6485.7573	99,186
Orange County	3.03	$75,176	1374.7366	3,121,251
Placer County	2.61	$73,260	104.58427	333,401
Plumas County	2.03	$50,817	6868.1404	20,917
Riverside County	3.13	$58,168	4720.1655	2,088,322
Sacramento County	2.7	$57,779	119.66526	1,424,415
San Benito County	3.09	$72,228	4912.0392	57,784
San Bernardino County	3.32	$56,575	6882.4088	2,055,766
San Diego County	2.74	$63,727	1494.0728	3,146,274
San Francisco County	2.42	$71,957	1735.5519	824,525
San Joaquin County	3.12	$54,711	684.64345	685,660
San Luis Obispo County	2.39	$57,722	1641.8036	269,337
San Mateo County	2.74	$84,684	820.65511	739,469
Santa Barbara County	2.72	$59,850	4018.6351	428,655
Santa Clara County	2.91	$87,287	594.14817	1,837,075
Santa Cruz County	2.61	$67,070	763.87473	266,519
Shasta County	2.56	$43,836	14.578032	182,236
Siskiyou County	2.15	$36,171	245.83852	45,971
Solano County	2.9	$68,603	1050.5387	426,757
Sonoma County	2.53	$63,768	1320.2397	484,470
Stanislaus County	3.13	$51,601	1711.6781	525,903
Sutter County	2.94	$52,505	282.70434	95,878
Tehama County	2.56	$36,731	238.47198	62,419
Tulare County	3.36	$43,995	1161.9141	435,254
Tuolumne County	2.29	$47,466	228.64261	56,799
Ventura County	3.05	$76,269	1886.6025	831,587
Yolo County	2.76	$58,851	517.53234	199,066
Yuba County	2.86	$45,727	204.31822	71,929

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The monthly load duration patterns for the various climate regions are not similar. Weather patterns and local diurnal temperatures range from the very stable coastal areas to the extreme of the south central valley.

3.1.1 Wasco and Monterey as Real World Examples

As an example of the impacts due to different weather patterns, the City of Wasco household has an average annual income of $36,594 dedicated to supporting a family of four, whereas the city of Monterey enjoys an average income of $60,363 dedicated to a family of two. The Wasco family of four inhabits a dwelling that is situated in a climate region where the temperature swings are such that in June and July the Monterey Maximum temperature approaches the Wasco Minimum temperature. Conservation can come easily to the more temperate communities. This trend holds true for most of the coastal climate regions and the central valley regions. [6]

Table 2

		Monterey	Wasco
Household Size	Pax	2.16	3.76
Median Income	$(2008)	60363	36594
Income per House member	$(2008)	27945.83	9732.447
Mortgage	$(2008)	1766	839
Non-Mrgtg HH Cost	$(2008)	314	238
Income to Non-Mrgtg ratio		192.2389	153.7563
Per household consumption	kWh	5956.357	9078.34

[6] California Department of Finance

3.1.2 Weather Variation between Wasco and Monterey

The Poisson distribution (bell-curve) of energy demand due to temperature variation for the central valley is different than that for the coastal communities.[7] The average consumption (which currently drives the baseline) is higher in the central valley region and the spread is greater. The chart below shows the seasonal variation in average maximum and minimum monthly temperatures.

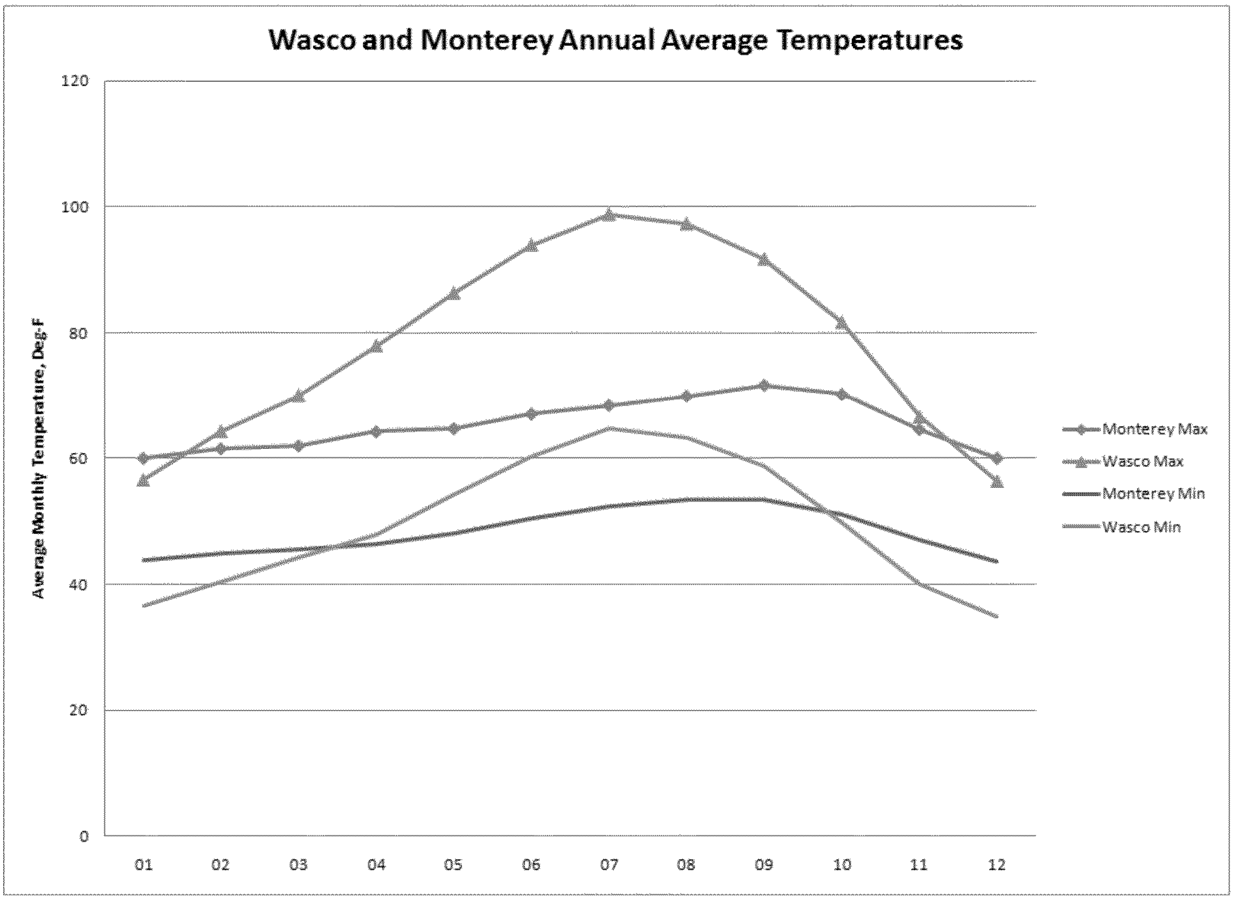

Figure 3-1

The chart above should be considered in relation to the 65 °F reference temperature for cooling degree days. [8]

> ***"Hot weather (CDD) as reported in Global Energy's Velocity Suite database increases electricity use substantially; cold weather (HDD from the same database) has an insignificant effect". [emph]***[CEC-200-2009-015]

[7] The Poisson function can be used to describe the demand distribution and provides a useful way to establish the percentage of time when a demand will be expected.

[8] NOAA data

3.2 Cooling Degree Days as a Means to Estimate Demand Duration between Wasco and Monterey

Tier rates may create some load shifting but will not bring more temperate regions into the same conservation imperative felt by the hotter regions. The central valley's regional residential demand duration curves will by design have greater seasonal variation, a higher 100% demand duration, a higher 50% residential demand duration point and a higher peak demand. Therefore the allocation of tier levels based on a generalized Poisson function driven distribution (i.e., average, 101% to 130%, 131% to 200%, 201% to 300%, 300%+) may show some statistical validity for the system-wide average but have no rational bearing on actual regional usage patterns at the regional household level. Whether the baseline is based on 50%, 55% or 60% is of little difference in terms of overall inter-climate region discrimination. The figure below shows the mapped 2009 tiers based on a 60% baseline. The 50% baseline would remap the tier 1 intercept to the 50% load duration point shifting access to approximately 5% less.

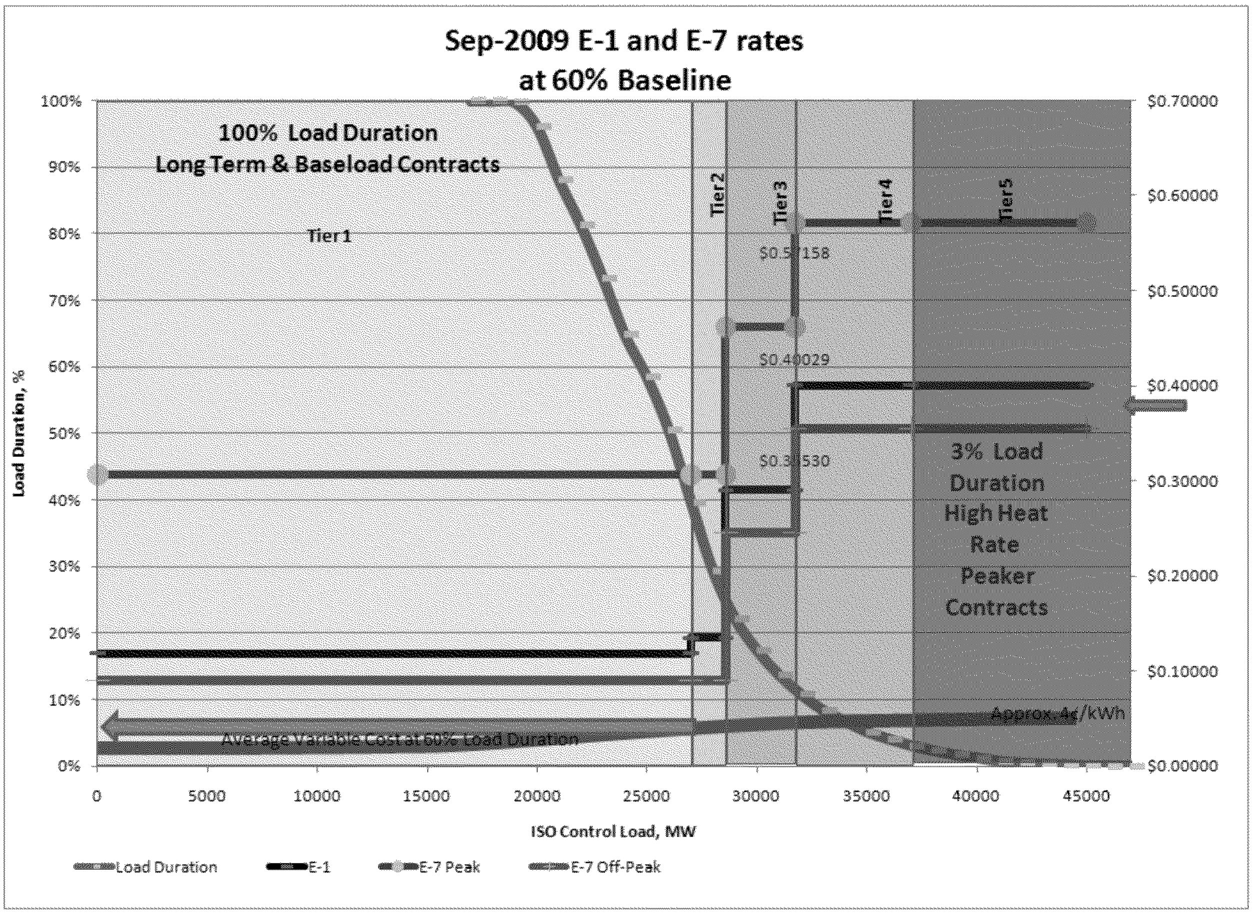

Figure 3-2

The table below shows the cooling degree day (CDD) variation from region to region (in this case Wasco and Monterey) helps define the variation in tiered electrical consumption of various households dependent on climate region.[9] The summer rate period is highlighted.

Table 3

Monthly Degree Day Data						
	Monterey			Wasco		
Month	Base Year (2009)					
	HDD	CDD	TDD	HDD	CDD	TDD
Jan	331	1	332	451	0	451
Feb	328	0	328	273	3	276
Mar	384	0	384	190	24	214
Apr	308	28	336	122	84	206
May	229	3	232	0	365	365
Jun	136	0	136	0	367	367
Jul	161	0	161	0	674	674
Aug	103	15	118	0	555	555
Sep	140	13	153	3	487	490
Oct	210	11	221	76	66	142
Nov	320	1	321	285	7	292
Dec	461	0	461	513	0	513
Total	3111	72	3183	1913	2632	4545
Summer	979	42	1021	79	2514	2593

The next table summarizes the data above annually and for the summer period.

[9] NOAA, Degree day is a quantitative index demonstrated to reflect demand for energy to heat or cool houses and businesses.. A mean daily temperature (average of the daily maximum and minimum temperatures) of 65°F is the base for both heating and cooling degree day computations. Heating degree days are summations of negative differences between the mean daily temperature and the 65°F base; cooling degree days are summations of positive differences from the same base. For example, cooling degree days for a station with daily mean temperatures during a seven-day period of 67,65,70,74,78,65 and 68, are 2,0,5,9,13,0,and 3, for a total for the week of 32 cooling degree days.

Table 4

Degree Days for Region Q and W			
	HDD	CDD	Total
	Annual		
Wasco	1913	2632	4545
Monterey	3111	72	3183
Difference	-1198	2560	1362
Ratio	-0.62624	35.55556	0.427898
	Summer		
Wasco	79	2514	2593
Monterey	979	42	1021
Difference	-900	2472	1572
Ratio	-11.3924	58.85714	1.539667

3.2.1 Relationship of Tier Penetration between Wasco and Monterey

The table below shows the 5-tier increments based on a 60% baseline. Consider the Region Q and W (highlighted) and their increments in relationship to the temperature patterns, one can readily see that the increments in the coastal region are such that the average coastal user will rarely penetrate the upper tiers due to high HVAC demand whereas the average Central Valley user will experience a greater disproportionate number of degree days especially if the baseline is set as high as 60%, thereby allowing the coastal region to enjoy more discriminatory access to cheaper tier 1 and tier 2 energy.

Table 5

Residential										
ELECTRIC										
Baseline Territories and Quantities										
Effective May 1, 2008 - Present										
	Winter					Summer				
	(Effective November 1, 2008)									
TERRITORY	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
ALL-ELEC.										
(Code H)	Daily					Daily				
P	35.5	10.7	21.3	35.5	35.5	20.1	6.0	12.1	20.1	20.1
Q	22.9	06.9	13.7	22.9	22.9	11.1	3.3	6.7	11.1	11.1
R	32.6	09.8	19.6	32.6	32.6	23.2	7.0	13.9	23.2	23.2
S	32.0	09.6	19.2	32.0	32.0	20.1	6.0	12.1	20.1	20.1
T	20.2	06.1	12.1	20.2	20.2	11.1	3.3	6.7	11.1	11.1
V	27.5	08.3	16.5	27.5	27.5	16.5	5.0	9.9	16.5	16.5
W	29.2	08.8	17.5	29.2	29.2	27.3	8.2	16.4	27.3	27.3
X	22.9	06.9	13.7	22.9	22.9	12.2	3.7	7.3	12.2	12.2
Y	30.9	09.3	18.5	30.9	30.9	15.0	4.5	9.0	15.0	15.0
Z	31.5	09.5	18.9	31.5	31.5	12.8	3.8	7.7	12.8	12.8
Avg	28.5					16.9				
BASIC ELEC.										
(Code B)										
P	12.9	3.87	7.74	12.90	12.90	16.5	5.0	9.9	16.5	16.5
Q	12.6	3.78	7.56	12.60	12.60	8.3	2.5	5.0	8.3	8.3
R	12.3	3.69	7.38	12.30	12.30	18.1	5.4	10.9	18.1	18.1
S	12.7	3.81	7.62	12.70	12.70	16.5	5.0	9.9	16.5	16.5
T	9.8	2.94	5.88	9.80	9.80	8.3	2.5	5.0	8.3	8.3
V	11.1	3.33	6.66	11.10	11.10	9.6	2.9	5.8	9.6	9.6
W	11.4	3.42	6.84	11.40	11.40	19.4	5.8	11.6	19.4	19.4
X	12.6	3.78	7.56	12.60	12.60	12.1	3.6	7.3	12.1	12.1
Y	13.3	3.99	7.98	13.30	13.30	12.2	3.7	7.3	12.2	12.2
Z	11.6	3.48	6.96	11.60	11.60	8.8	2.6	5.3	8.8	8.8
Avg	11.7					13.0				

The ratio of summer all electric baseline allowance between residents in Wasco and those in Monterey is 2.45 yet the Wasco resident **experiences 59 times more Cooling Degree Days in the summer, c**learly underscoring the variation in incremental demand relative to the climate region baselines, see table below.

Table 6

Climate Region	Summer All Electric Tier-Based Consumption				
	1	2	3	4	5
Q	11.1	3.33	6.66	11.1	11.1
W	27.3	8.19	16.38	27.3	27.3
Ratio	2.459459	2.459459	2.459459	2.459459	2.459459
	Summer Basic Electric Tier-Based				
	1	2	3	4	5
Q	8.3	2.49	4.98	8.3	8.3
W	19.4	5.82	11.64	19.4	19.4
Ratio	2.337349	2.337349	2.337349	2.337349	2.337349

Given the higher number of persons per household in the Central Valley it is possible to argue that there is a basic need for baseline energy that is greater and dominates the baseline over HVAC. Treating the baseline consumption as a basic quantity driven by uses other than HVAC would infer that only a few of the CDD are actually allocated to the baseline itself and all other CDD (HVAC load) are followed by energy drawn from other higher tiers progressively. Using the Monterey dwellers use as the base, starting with the 42 summer CDD for Monterey and multiplying by the baseline ratio of 2.45 gives 102.9 CDD as equivalent CDD dedicated to baseline demand (as if both Monterey and Wasco had similar HVAC and non-HVAC load patterns), the remaining baseline is assumed to be due to non-HVAC uses, attributed to the household dwellers. Subtracting 102.9 CDD from Wasco's 2514 CDD leaves 2411 CDD to be divided into the tier structure [i.e., 100% to 130% (tier 2), 131% to 200% (tier 3), 200% to 300% (tier 4) and 300%+(tier 5)]. Dividing the 2411 CDD into thirds and applying the results in incremental CDD intervals as follows:

Table 7

Adjusted tier based CDD: Alternative 1			
	Wasco	Monterey (=base)	Ratio
tier 1	102.9	42	2.45
tier 2	267	42	6.357143
tier 3	535	42	12.7381
tier 4	803	42	19.11905
tier 5	803	42	19.11905

This would indicate that a Wasco resident using all electric will purchase 6 times more tier 2, 12 times more tier 3, 19 times more tier 4 and 19 times more tier 5 to follow their HVAC demand in the summer.

Another approach is to assume that the Wasco residential HVAC load is proportionally equal to non-HVAC and that an equal number of CDD are covered in the baseline. In this instance the summer CDD are simply divided in two equal parts (assuming a 50% baseline) of the summer CDD and the remainder is allocated to the other 4 tiers according to previously acceptable allocation rate schemes.

Table 8

Adjusted tier based CDD: Alternative 2			
	Wasco	Monterey (=base)	Ratio
tier 1	1257	42	29.92857
tier 2	139.527	42	3.322071
tier 3	279.054	42	6.644143
tier 4	419	42	9.97619
tier 5	419	42	9.97619

In this scenario, a Wasco residence using all electric will purchase 3 times more tier 2, 7 times more tier 3, 10 times more tier 4 and 10 times more tier 5 to follow their HVAC demand in the summer.

Neither analysis reveals a relationship that ties to a simple 2.45 ratio between Wasco and Monterey. In fact it would be difficult to develop a fair single distribution formula for a multi-tier approach that reflects the unique differences between all the cities and counties served by PG&E. A more rigorous analysis would reveal that residents in coastal regions have more disposable income and personal appliances than Central Valley residents.

4 Higher Tier Rates and Residential Rooftop Solar

Makers of arguments that higher tiers should have substantially higher rates that stimulate installation of legislatively desired rooftop solar have to consider the point presented above indicating that the Central Valley resident will be forced to purchase 20 to 40 times more tier 4 and tier 5 energy per household. Any estimate of the program costs would then have to be allocated according to the misdistribution and number of households in selected climate regions. Perhaps more import is the fact that the greater cost burden driven by a rooftop solar industry price point is the discriminatory effect on an income basis by climate region.

Table 9

		Monterey	Wasco
Household Size	Pax	2.16	3.76
Median Income	$(2008)	60363	36594
Income per House member	$(2008)	27945.83	9732.447
Mortgage	$(2008)	1766	839
Non-Mrgtg HH Cost	$(2008)	314	238
Income to Non-Mrgtg ratio		192.2389	153.7563
Per household consumption	kWh	5956.357	9078.34

One can see that the added tier-rate-imposed-burden of 20 to 40 times more rooftop solar inducing rates is borne by individuals having three times less spending power. Without judging the prudency of developing a multi-tiered arrangement that provides no avoided cost tests or reflects any benefit of economy of scale in lowering prices, the use of prior approved rates and the ratemaking philosophy as a surrogate for some of the suggested multi-tiered allocations in this GRC P-2 and future ratemaking proceedings shows that Valley residents will bear more of the higher rates that have been or will be imposed.

Table 10

Rate Schedule	Rate Design	Minimum Energy Charge (per meter per day)	Discount (per dwelling unit per day)	Minimum Average Rate Limiter (per kWh per month)	Energy Charge[1/, 2/] ($/kWh)					"Average" Total Rate[3/] (per kWh)
			ES, ET, ESL & ETL Only	ES, ET, ESL & ETL Only	Tier 1 (Baseline)[4/]	Tier 2 (101-130% of baseline)	Tier 3 (131-200% of baseline)	Tier 4 (201-300% of baseline)	Tier 5 (Over 300% of baseline)	
Residential Schedules: E-1, EM, ES, ESR, ET	Tiered Energy Charges	$0.14784	ES = $0.10579 ET = $0.37925	ES and ET $0.04892	$0.11877	$0.13502	$0.28562	$0.42482	$0.49778	$0.18895
Residential CARE Schedules: EL-1, EML, ESL, ESRL, ETL	CARE Tiered Energy Charges	$0.11828	ESL = $0.10579 ETL = $0.37925	ESL and ETL $0.04892	$0.08316	$0.09563	$0.09563	$0.09563	$0.09563	$0.08668

Rate Schedule	Rate Design	Minimum Energy Charge (per meter per day)	Discount (per dwelling unit per day)	Minimum Average Rate Limiter (per kWh per month)	Energy Charge[1/, 2/] ($/kWh)					"Average" Total Rate[3/] (per kWh)
			ES, ET, ESL & ETL Only	ES, ET, ESL & ETL Only	Tier 1 (Baseline)[4/]	Tier 2 (101-130% of baseline)	Tier 3 (131-200% of baseline)	Tier 4 (201-300% of baseline)	Tier 5 (Over 300% of baseline)	
Residential Schedules: E-1, EM, ES, ESR, ET	Tiered Energy Charges	$0.14784	ES = $0.10579 ET = $0.37925	ES and ET $0.04892	$0.11877	$0.13502	$0.27572	$0.40577	$0.47393	$0.18471
Residential CARE Schedules: EL-1, EML, ESL, ESRL, ETL	CARE Tiered Energy Charges	$0.11828	ESL = $0.10579 ETL = $0.37925	ESL and ETL $0.04892	$0.08316	$0.09563	$0.09563	$0.09563	$0.09563	$0.08668

The two PG&E rate schedules above show that the tier 4 and tier 5 rates can easily range from 40 ¢/kWh to 50¢/kWh, of which Central Valley residents will have to purchase 20 to 40 times more than other milder regions. Using the (1/1/ 2010 to 2/28/2010) summer rate schedule and assuming a hypothetical 70kWh per day usage for 30 days during a summer month, the breakdown for the average home in the Central Valley as compared to the home in Monterey would indicate that half of the household bill in the Central Valley would mostly go to HVAC purchased at tier 3 or greater.[10]

The first of the two tables below show the allocation of 70 kWh per day usage to each tier and the bill impact, the second shows a relative bill impact of the use pattern one might see in Monterey during the same day and their summer baseline and tier increments. Assuming that the relative difference in CDDs between Wasco and Monterey, the daily demand in Monterey on any given summer day should be a fraction of Wasco's use. One can see the trend below that shows an equivalent household in Monterey would pay some percentage less, possibly as low as 10% but more likely the non-HVAC costs would result in a comparable bill that reflects approximately 30% of Wasco's usage on a given summer day.[11]

Table 11

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	11.64	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
70	kWh	70	50.6	44.78	33.14	13.74	0
Increment		19.4	5.82	11.64	19.4	19.4	0
Residual		19.4	5.82	11.64	19.4	13.74	
Rate	$/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$ 2.30	$ 0.79	$ 3.21	$ 7.87	$ 6.51	
30 days	$	$ 69.12	$ 23.57	$ 96.28	$ 236.16	$ 195.35	$620.49

Table 12

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	30%	25%
kWh/d	70	35	31.5	28	24.5	21	17.5
Est. Monthly Bill	$ 620.49	$ 337.29	$ 287.53	$ 237.77	$ 188.00	$144.52	$101.91
Avg. Price ($/kWh)	0.295472	0.321229	0.304262	0.283054	0.255786	0.229393	0.194118

[10] Based on data from EIA , http://www.eia.doe.gov/emeu/recs/recs2005/c&e/detailed_tables2005c&e.html , 2005 data referenced to Excel spreadsheet "Consolidated EIA Residential Data", "Appliance kWh", "AC Consumption kWh", "30 day Appl and AC usage" (Attached)

[11] Based on EIA RECS data the equivalent Monterey demand commensurate with Wasco's monthly average of 70kWh daily for July is 19.6 kWh daily (including appliances and HVAC) based on East South Central data, see Excel spreadsheet "Consolidated EIA Residential Data", "Appliance kWh", "AC Consumption kWh", "30 day Appl and AC usage"

If the daily demand is 100 kWh per days the costs are even more skewed. The next two tables show the same impact for 100 kWh per day.

Table 13

Tier		1	2	3	4	5	Total
Region	W	19.4	5.82	11.64	19.4	19.4	
Daily		Residual after Summer Basic Elec. Tier					
100	kWh	100	80.6	74.78	63.14	43.74	
Increment		19.4	5.82	11.64	19.4	19.4	
Residual		19.4	5.82	11.64	19.4	43.74	
Rate	$/kWh	0.11877	0.13502	0.27572	0.40577	0.47393	
Cost	$	$ 2.30	$ 0.79	$ 3.21	$ 7.87	$ 20.73	
30 days	$	$ 69.12	$ 23.57	$ 96.28	$ 236.16	$ 621.89	$1,047.03

Table 14

Region	W	Q					
Reduced Demand due to fewer CDD	Base	50%	45%	40%	35%	30%	25%
kWh/d	100	50	45	40	35	30	25
Est. Monthly Bill	$1,047.03	$ 550.56	$ 479.47	$ 408.38	$ 337.29	$266.20	$195.11
Avg. Price ($/kWh)	0.3490097	0.367039	0.355163	0.340317	0.321229	0.295779	0.260149

The total electricity bill for the Wasco resident may exceed their mortgage payment.[12] In this instance, the resident in Wasco must also pay over $650 for tier 4 and tier 5, nearly four times as much as the entire bill for a resident in Monterey. These residential rooftop solar units only achieve peak load following for three months of a given year while bifurcating the orderly fossil-fired dispatch for 9 months, potentially creating additional unrealized costs related to fossil-fired costs to restart and follow declining solar output in the post solar to system peak.[13] Essentially,

[12] Wasco, Ca : Mean price in 2000: All housing units: $80,700 or $708/mo. at 10%, 30yr. (US Census for zip code 93280)

[13] Excel Spreadsheets: "Load Duration for Solar by Month", (attached)

the Wasco resident is forced to consider converting to solar (based on their penetration into the tier 4 and tier 5 energy cost) whereas the Monterey resident has no need to consider the avoided cost. This inequity should not be considered without recalling the fact that the per-household income is 2.87 times less in Wasco, from which the purchase of solar panels must be paid.

Assuming that solar requires prices in excess of 30¢/kWh, to stimulate the necessary cost (and thereby create the need to use funds to avoid the cost) one has to penetrate the tier 4 and tier 5 rates with sufficient energy requirements. Penetration of the tier 5 by increasing demand to 120 kWh simply exacerbates the discrepancy.

The discriminatory effects discussed above in this section are basically the same for TOU multi-tier rates.

5 Summary

Tier rate structures are not well founded in regulatory history and do not equally distribute a signal to conserve. Further, tier rates appear to favor the wealthier households in milder climate regions. Multiple tiers above baseline should be abandoned in favor of a simpler formula that allows compliance with AB 1X until such time as AB 1X flaws can be remedied.

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