Evaluation of Future QF Pricing and Contracting Policy

Prepared testimony of
William B. Marcus

on behalf of
The Utility Reform Network
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Introduction

This testimony is presented by William B. Marcus, Principal Economist of JBS Energy, Inc. on behalf of The Utility Reform Network (TURN). Mr. Marcus has 27 years of experience in this industry, has appeared before this Commission on many occasions, and has filed testimony or formal comments before about 35 federal, state, provincial, and local courts and regulatory bodies in the U.S. and Canada. Mr. Marcus' qualifications are attached.

TURN recommends reform of the avoided cost pricing parameters to provide for QF contracts based on either (1) electricity market prices alone, or (2) a "modified market-based" contract that pays QFs a capacity payment based on the deferral value of a new Combustion Turbine (CT) and market energy prices *capped at the costs of generating energy from such a new CT*. Such contracts should be available to existing QFs as a contract renewal option and to a few other relatively small or specialized entities for which a QF contract may be the only viable way to participate in the market.

Pricing Terms

The current Standard Offer 1 avoided cost methodology provides a pricing formula based on the cost of gas, with average implicit heat rates in the range of 9,000 to 12,000 Btu/kWh[1] plus capacity payments that were theoretically based on the full deferral value of a combustion turbine for PG&E and SDG&E and a lesser amount (10% of a CT value) for Edison.

The payment under this contract should be a market-based price. Merely extending expiring contracts using a current SRAC-style energy price together with CT-based capacity payments would create *a severe burden on ratepayers* and should be rejected by the Commission. Now that there exists a wholesale market that appears to be functioning reasonably, we do not need an administrative determination of avoided cost based on hypothetical resource commitments.

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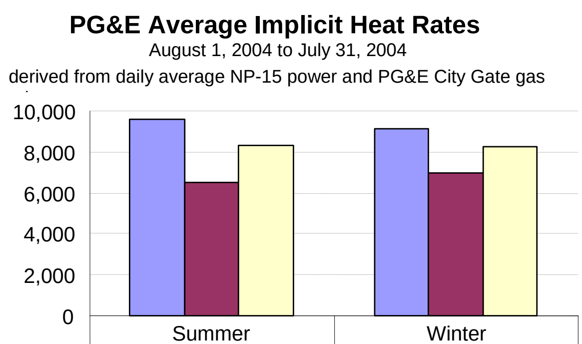
[1] For example, the August 2005 PG&E avoided cost posting has an all-hours average avoided cost of $59.63/MWh and a gas price of $6.473/MMBtu for an implicit heat rate of 9,212 Btu/kWh. PG&E's winter avoided costs have higher implicit heat rates.

In today's electric utility environment, true "avoided cost" prices mandated by PURPA can only be based on "market" prices.[2] Such market prices could come in several variants. The first and most basic appropriate payment to QFs consistent with PURPA "avoided costs" would be an unhedged market price contract, which could be based on ISO imbalance prices[3], on-peak and off-peak prices reported by a publicly available service such as the Intercontinental Exchange (ICE) or Dow Jones, or hourly prices from a future day-ahead market when and if developed.[4] These market prices are for firm energy, which includes both energy and capacity, and represent utilities' "avoided costs" as specified by PURPA. Market prices over the years since 2000-01 have implicit heat rates that are considerably less than the SRAC avoided cost payments to QFs, even before adding in a combustion turbine payment, as shown in Figure 1 below.[5]

<u>Figure 1</u>



	Summer	Winter
On Peak Heat Rate	9,569	9,151
Off Peak Heat Rate	6,493	6,998
Daily Heat Rate	8,324	8,263

2 This would not be true in a situation where the "market" becomes dysfunctional, as was the case in California in 2000-01, when FERC ultimately was forced to intervene and establish "mitigated market clearing prices."

3 The use of ISO imbalance prices is not our preferred option, because ISO imbalance prices truly represent the last few megawatts and can swing dramatically based on minute-to-minute imbalances between load and generation rather than day-to-day loads and resources.

4 This would be our preferred option.

5 See Appendix A, which shows daily NP-15 on-peak and off-peak electric prices, gas prices, and implicit heat rates from the Intercontinental Exchange for the last 12 months.

The implicit heat rates in this figure are based on PG&E City Gate gas prices; actual implicit heat rates including LDC local transmission and distribution costs would actually be somewhat lower. By comparison, PG&E's SRAC formula yields implicit heat rates of about 10,840 Btu/kWh averaged across the year (9,360 Btu/kWh summer and 12,324 Btu/kWh winter for the 12 months from August 2004 to July 2005).

As a second variant, the market price could be combined with a "CT proxy call option" based on the costs and performance parameters of a modern CT for a five or ten year contract term at the QF's option. This contract would pay QFs a fixed capacity payment based on the deferral value of a modern CT proxy.[6] QFs' energy payments would still be set equal to market prices, but in return for the fixed capacity payment, QF energy payments would be capped at the "strike price" of the CT proxy. Such a contract containing a "CT proxy call option" would provide the utility more certainty that QFs providing competitively-priced power would be available when required, and would also reasonably reflect a utility's avoided costs over a contract period of five to ten years. While the market price is the instantaneous avoided cost today, an argument can be made that the market price with a "CT proxy call option" is an intermediate term avoided cost, because it is a step that could reasonably be taken by a utility both to assure capacity availability and to hedge against market energy price spikes. Capacity payments based on the deferral value of a CT would also clearly compensate a QF for the value it provides in helping the utility meet its obligations under the Resource Adequacy Requirement to provide physical capacity.[7]

The sum of unhedged market energy prices and CT capacity costs is <u>greater</u> than total avoided cost.[8] The combination of a CT capacity price and the call option to limit market

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[6] Although making this proposal for QF pricing based on historical continuity, TURN does not abandon its argument that marginal capacity costs, based on the least-cost resource that provides capacity, may be lower than a CT based on incremental duct firing capacity at combined cycle plants or other potentially cheaper options.

[7] TURN notes that the specific details of what will be defined as "RAR-qualifying capacity" and the means for valuing such capacity, if any, aside from its economic hedge value are issues still to be addressed by this Commission. TURN will revisit this issue as appropriate as the Commission provides further direction on these issues.

[8] This phenomenon was largely not material in the late 1970s and early 1980s when current CT-based contracts were developed. Technological change has rendered the old assumption that the

energy prices is the highest possible measure of avoided cost. As an alternative to a QF contract, a utility could build or contract with a CT to hedge against the highest cost and highest load hours. It would actually run the CT only when the market price exceeded the running cost of the CT, and would therefore never pay higher market prices for the output that could be generated by the CT.

Two approaches could be taken to assure that QF pricing does not exceed avoided cost. The first would be to discount the CT capacity cost by the savings in fuel and purchased power — reflecting that the <u>net</u> cost of capacity from a modern CT is the gross cost less the savings that it would generate when it ran and displaced energy at higher market prices from inefficient steam plants or from shortage-based prices. A second component of the discount would reflect that a dispatchable CT, when not operating, can be bid into the ISO's ancillary services markets and create some revenue that would not be created by the QF (and is thus not part of the CT-based avoided cost for the QF). This approach has the disadvantage of requiring the development of a controversial administrative formula to estimate the fuel savings that arise from actually operating the CT capacity.

TURN has thus selected a second, more easily administered alternative, which provides QFs a CT-based capacity payment and market energy payments that are limited by the strike price of the CT proxy used to set the capacity payment. Under this alternative, the capacity payment would be based on current CT prices – not past prices from old contracts that were much higher in real dollar terms, contained much higher escalation rates and much higher interest rates, equity returns, and corporate income tax rates than prevail today. The first year price would be fixed in advance based on a real economic

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full avoided cost is the cost of a combustion turbine plus the market price obsolete. First, the economic theory that established that the capacity value is based on the cost of a combustion turbine was established in the late 1970s when CTs were far less efficient than they are today. Heat rates of 15,000 Btu/kWh were common at that time. A CT therefore had little or no energy value and would be the cheapest cost of pure capacity at that time. Technology has rendered this old theory obsolete. Modern CTs are very different. They have a heat rate in the range of 10,000 Btu/kWh, which is considerably less than many older steam plants (even after factoring in $5-$10/MWh of variable O&M), while offering more flexible operations than steam plants that must run overnight to meet peak on two consecutive days. Therefore, we can no longer just claim that marginal energy costs – or market prices – plus a CT equals marginal generation costs, because the CT produces significant fuel savings relative to older steam plants and even more savings when compared to market prices.

carrying charge rate but would escalate each year with actual inflation through the contract term. The contract would not be levelized, thereby eliminating one form of potential damages from non-performance. The first year price (using a 25-year CT life and an economic carrying charge rate) is about $61 per kW-year (2004 dollars). [See Appendix B for information on the computation.]

More importantly, in exchange for receiving a CT-based capacity price, the QF market energy price should be capped at the cost of energy from a modern combustion turbine. The cap should be based on a heat rate in the range of 10,000 Btu/kWh to cover CT energy (full load heat rate of 9,300 Btu/kWh from CEC data, plus amortization of start-up fuel over hours run and partial load heat rates during ramping) together with variable CT O&M in the range of $8-10/MWh (based on amortization of overhaul costs, variable costs, and amortization of non-fuel start-up costs over hours run). If hourly prices can be used for the market price, then the cap should apply hourly.

We discuss how the capacity proxy call option could work for both firm and as-available QFs below.

Interaction of Pricing and Contracting

Assuming that avoided cost pricing is reformed to approximate actual market prices, QFs should be permitted to execute either pure market-price or "CT proxy call option" contracts of 5 or 10 years with an IOU, so long as the contract terms are also reformed to provide real value to ratepayers.

If avoided cost pricing is reformed to approximate market prices, TURN could support the issuance of long-term contracts to existing QFs and relatively small new QFs, for a maximum of 10 years in duration. Such contracts would provide some measure of stability and preserve the economically efficient portion of the existing QF resource base, while allowing the orderly integration of power from smaller distributed generators into utility systems under reasonable terms and conditions. TURN could support these contracts for all existing QFs; for all new QFs under 10 MW or the minimum size limit at which an entity can bid into a utility's all-source (or renewable if a renewable QF) solicitations for power, whichever is greater;[9] and for new QFs up to 25 MW who consume at least 25% of their power internally and sell all of their remaining surplus energy above their internal consumption to the utility. This latter provision is reasonable because QFs cannot sell surplus power directly to the ISO under current grid rules.[10]

Any reissued long-term "CT proxy call option" contracts should be modified to include the following terms:

- Considerably higher availability factors before firm capacity bonuses are earned – which should be well over 95% for CT-based contracts -- and a sliding scale of penalties for lower availability than the 90% range. Higher availability requirements reflect the performance of modern CTs, as reflected in current utility contracts.[11]

- Unlike current QF contracts which require actual energy production, if the firm QF agrees to run whenever called upon by the utility (subject to unit availability), then demonstrated *availability*, not actual generation, should be used to determine whether the availability target is met for a firm CT call option contract.

- An as-available "CT proxy call option" contract should be permitted for QFs with telemetering, where the amount of capacity paid the CT-based price would be based on the lesser of the resource adequacy value provided by the resource (as determined by the Commission in the future) or the average capacity deliveries in the ten hours with the highest load in each month.

- Full curtailment or partial curtailment (reflecting on-site steam load requirements) for a significant number of hours (e.g., on the order of 500-1000 hours per year –

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[9] If a utility reduces the size limit for qualifying to bid into a solicitation and waives credit requirements for QFs under 25 MW, the maximum size at which the standard contract must be offered to new QFs should also be reduced.

[10] The ISO's rules currently do not allow a generator to serve local on-site load and sell only surplus power to the ISO. In the energy crisis of 2000-01, the ISO shortsightedly required QFs coming off their contracts to curtail output, and wouldn't take surplus power in excess of internal loads. This rule appears to violate the purchase requirements of PURPA and FERC rules implementing it since 1981 that require the QF to have the option to serve its own load and sell surplus.

[11] The CalPeak-CDWR contracts requires 96% availability in peak summer and winter months and 94% in other months (subject to major maintenance allowances in other months), while the Wellhead Power-CDWR contracts require 97% in peak summer and 94% for the rest of the year. Other CDWR contracts for combined cycle (or sequenced CT and CC) projects required availability of 98% summer, 94% winter (GWF), 95% year-round (High Desert combined cycle), and 98% summer, 92% in the remainder of the year (Calpine Los Esteros).

not necessarily limited to off-peak, because certain early morning peak hours often have excess generation due to the inflexible terms of 6x16 contracts from CDWR and other sources) - would be appropriate if the price is based on a day-ahead or month-ahead 6x16, 6x8 or 1x24 factor that does not fully value hourly phenomena.

- Changing the summer period for capacity to exclude May and October, particularly if actual performance rather than demonstrated availability is required.

- Setting payments such that most but not all capacity is earned in summer months. Several Edison-related contracts have about 80% of capacity payments earned in summer months including the Mission Sunrise-CDWR contract and the Mountainview combined cycle project.

- Because these proposed contracts are largely market-based, some of the restrictions on expansion of QF output that have been vexatious to all parties would not necessarily need to be included in new contracts to the degree that they have been included in existing QF contracts.

By directing utilities to make these changes, the Commission would facilitate contracting that provides capacity to utilities under commercially reasonable and competitive terms.

Appendix A - ICE Data 12 months from August 2004 to July 2005

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
08/01/2004	Sun	Summer	-		54.72	6.23		8,779	8,779
08/02/2004	Mon	Summer	-	63.08	54.72	6.23	10,120	8,779	9,673
08/03/2004	Tue	Summer	-	60.07	43.08	6.04	9,937	7,127	9,001
08/04/2004	Wed	Summer	-	59.25	43.11	5.98	9,902	7,205	9,003
08/05/2004	Thu	Summer	-	59.43	42.78	5.94	10,000	7,199	9,066
08/06/2004	Fri	Summer	-	57.62	41.74	5.90	9,758	7,069	8,862
08/07/2004	Sat	Summer	-	57.62	41.74	5.84	9,865	7,146	8,959
08/08/2004	Sun	Summer	-		50.38	5.84		8,625	8,625
08/09/2004	Mon	Summer	-	64.41	50.38	5.84	11,027	8,625	10,227
08/10/2004	Tue	Summer	-	69.85	46.24	5.98	11,684	7,735	10,367
08/11/2004	Wed	Summer	-	68.67	44.13	6.02	11,416	7,336	10,056
08/12/2004	Thu	Summer	-	64.04	43.00	5.83	10,980	7,373	9,778
08/13/2004	Fri	Summer	-	59.98	41.92	5.75	10,440	7,297	9,392
08/14/2004	Sat	Summer	-	59.98	41.92	5.63	10,661	7,451	9,591
08/15/2004	Sun	Summer	-		47.27	5.63		8,402	8,402
08/16/2004	Mon	Summer	-	58.20	47.27	5.63	10,345	8,402	9,697
08/17/2004	Tue	Summer	-	57.80	40.13	5.66	10,211	7,089	9,170
08/18/2004	Wed	Summer	-	57.35	40.78	5.53	10,369	7,373	9,370
08/19/2004	Thu	Summer	-	57.39	40.42	5.49	10,446	7,357	9,417
08/20/2004	Fri	Summer	-	54.55	40.03	5.41	10,080	7,397	9,185
08/21/2004	Sat	Summer	-	54.55	40.03	5.44	10,019	7,352	9,130
08/22/2004	Sun	Summer	-		43.25	5.44		7,943	7,943
08/23/2004	Mon	Summer	-	54.46	43.25	5.44	10,002	7,943	9,316
08/24/2004	Tue	Summer	-	50.25	38.44	5.42	9,276	7,096	8,550
08/25/2004	Wed	Summer	-	45.94	36.44	5.24	8,759	6,948	8,155
08/26/2004	Thu	Summer	-	46.82	37.28	5.26	8,894	7,082	8,290
08/27/2004	Fri	Summer	-	46.47	37.43	5.19	8,952	7,210	8,371
08/28/2004	Sat	Summer	-	46.47	37.43	5.10	9,118	7,344	8,527
08/29/2004	Sun	Summer	-		44.53	5.10		8,738	8,738
08/30/2004	Mon	Summer	-	49.46	44.53	5.10	9,705	8,738	9,382
08/31/2004	Tue	Summer	-	51.33	37.27	5.05	10,167	7,382	9,238
09/01/2004	Wed	Summer	-	54.73	36.94	5.12	10,682	7,210	9,525
09/02/2004	Thu	Summer	-	54.73	36.94	5.15	10,625	7,172	9,474
09/03/2004	Fri	Summer	-	50.13	35.36	5.01	10,014	7,064	9,031
09/04/2004	Sat	Summer	-	50.13	35.36	4.58	10,937	7,715	9,863
09/05/2004	Sun	Summer	-		41.65	4.58		9,087	9,087
09/06/2004	Mon	Summer	Holiday		41.65	4.58		9,087	9,087
09/07/2004	Tue	Summer	-	48.50	35.77	4.58	10,582	7,804	9,656
09/08/2004	Wed	Summer	-	57.43	38.44	4.81	11,945	7,995	10,628
09/09/2004	Thu	Summer	-	54.51	36.83	4.99	10,934	7,388	9,752
09/10/2004	Fri	Summer	-	49.37	34.98	4.79	10,305	7,301	9,303
09/11/2004	Sat	Summer	-	49.37	34.98	4.74	10,408	7,374	9,397
09/12/2004	Sun	Summer	-		40.29	4.74		8,494	8,494
09/13/2004	Mon	Summer	-	49.16	40.29	4.74	10,363	8,494	9,740
09/14/2004	Tue	Summer	-	53.00	36.33	5.04	10,515	7,208	9,413
09/15/2004	Wed	Summer	-	52.79	35.48	4.91	10,751	7,225	9,576
09/16/2004	Thu	Summer	-	52.82	34.40	4.83	10,931	7,119	9,660
09/17/2004	Fri	Summer	-	47.05	32.43	4.70	10,018	6,905	8,980
09/18/2004	Sat	Summer	-	47.05	32.43	4.72	9,974	6,874	8,940

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
09/19/2004	Sun	Summer	-		37.64	4.72		7,979	7,979
09/20/2004	Mon	Summer	-	46.04	37.64	4.72	9,759	7,979	9,166
09/21/2004	Tue	Summer	-	47.91	33.90	5.15	9,301	6,581	8,394
09/22/2004	Wed	Summer	-	49.12	34.97	5.24	9,376	6,675	8,476
09/23/2004	Thu	Summer	-	50.21	34.94	5.47	9,181	6,389	8,250
09/24/2004	Fri	Summer	-	49.37	34.63	5.37	9,201	6,454	8,285
09/25/2004	Sat	Summer	-	49.37	34.63	5.09	9,694	6,800	8,729
09/26/2004	Sun	Summer	-		39.88	5.09		7,830	7,830
09/27/2004	Mon	Summer	-	49.82	39.88	5.09	9,782	7,830	9,131
09/28/2004	Tue	Summer	-	47.34	34.35	5.05	9,381	6,807	8,523
09/29/2004	Wed	Summer	-	46.65	34.81	5.08	9,189	6,857	8,411
09/30/2004	Thu	Summer	-	50.06	35.54	5.73	8,742	6,206	7,897
10/01/2004	Fri	Summer	-	50.78	36.42	5.46	9,293	6,665	8,417
10/02/2004	Sat	Summer	-	50.78	36.42	4.51	11,258	8,074	10,196
10/03/2004	Sun	Summer	-		38.74	4.51		8,588	8,588
10/04/2004	Mon	Summer	-	46.45	38.74	4.51	10,298	8,588	9,728
10/05/2004	Tue	Summer	-	48.60	34.50	4.98	9,761	6,929	8,817
10/06/2004	Wed	Summer	-	53.26	36.73	5.48	9,726	6,707	8,720
10/07/2004	Thu	Summer	-	53.26	36.73	5.49	9,705	6,693	8,701
10/08/2004	Fri	Summer	-	49.44	35.70	5.30	9,330	6,737	8,466
10/09/2004	Sat	Summer	-	49.44	35.70	4.52	10,941	7,900	9,927
10/10/2004	Sun	Summer	-		41.39	4.52		9,160	9,160
10/11/2004	Mon	Summer	-	51.17	41.39	4.52	11,324	9,160	10,602
10/12/2004	Tue	Summer	-	50.29	34.95	5.21	9,657	6,711	8,675
10/13/2004	Wed	Summer	-	52.87	37.25	4.71	11,220	7,905	10,115
10/14/2004	Thu	Summer	-	56.13	37.96	4.62	12,160	8,224	10,848
10/15/2004	Fri	Summer	-	58.58	36.25	5.23	11,207	6,935	9,783
10/16/2004	Sat	Summer	-	58.58	36.25	5.10	11,478	7,103	10,020
10/17/2004	Sun	Summer	-		40.50	5.10		7,936	7,936
10/18/2004	Mon	Summer	-	51.42	40.50	5.10	10,075	7,936	9,362
10/19/2004	Tue	Summer	-	49.10	34.50	5.45	9,003	6,326	8,111
10/20/2004	Wed	Summer	-	49.10	34.50	5.81	8,447	5,935	7,610
10/21/2004	Thu	Summer	-	49.10	34.50	6.54	7,510	5,277	6,766
10/22/2004	Fri	Summer	-	61.34	43.71	6.60	9,287	6,618	8,398
10/23/2004	Sat	Summer	-	61.34	43.71	6.76	9,075	6,467	8,206
10/24/2004	Sun	Summer	-		54.48	6.76		8,060	8,060
10/25/2004	Mon	Summer	-	65.39	54.48	6.76	9,675	8,060	9,136
10/26/2004	Tue	Summer	-	70.55	52.07	7.67	9,199	6,789	8,396
10/27/2004	Wed	Summer	-	71.07	54.10	7.67	9,263	7,051	8,525
10/28/2004	Thu	Summer	-	71.07	54.10	7.88	9,023	6,869	8,305
10/29/2004	Fri	Summer	-	71.65	56.42	6.49	11,036	8,690	10,254
10/30/2004	Sat	Summer	-	71.65	56.42	6.49	11,036	8,690	10,254
10/31/2004	Sun	Summer	-		56.70	6.49		8,733	8,733
11/01/2004	Mon	Winter	-	68.13	48.67	6.91	9,865	7,047	8,925
11/02/2004	Tue	Winter	-	76.65	53.72	7.18	10,677	7,483	9,612
11/03/2004	Wed	Winter	-	77.82	55.58	7.03	11,076	7,911	10,021
11/04/2004	Thu	Winter	-	79.83	56.08	7.42	10,753	7,554	9,687
11/05/2004	Fri	Winter	-	78.03	54.40	7.50	10,400	7,250	9,350
11/06/2004	Sat	Winter	-	78.03	54.40	6.43	12,144	8,466	10,918

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
11/07/2004	Sun	Winter	-		57.21	6.43		8,903	8,903
11/08/2004	Mon	Winter	-	67.50	57.21	6.43	10,505	8,903	9,971
11/09/2004	Tue	Winter	-	69.52	53.59	6.80	10,230	7,886	9,449
11/10/2004	Wed	Winter	-	61.43	48.86	6.02	10,196	8,110	9,501
11/11/2004	Thu	Winter	Holiday		48.86	6.17		7,921	7,921
11/12/2004	Fri	Winter	-	60.44	46.73	6.18	9,777	7,559	9,038
11/13/2004	Sat	Winter	-	60.44	46.73	5.95	10,166	7,860	9,397
11/14/2004	Sun	Winter	-		50.43	5.95		8,482	8,482
11/15/2004	Mon	Winter	-	60.69	50.43	5.95	10,208	8,482	9,633
11/16/2004	Tue	Winter	-	64.88	44.65	6.11	10,615	7,305	9,512
11/17/2004	Wed	Winter	-	66.80	46.05	6.45	10,349	7,134	9,278
11/18/2004	Thu	Winter	-	67.43	44.33	5.88	11,460	7,534	10,152
11/19/2004	Fri	Winter	-	57.55	44.28	5.79	9,935	7,644	9,171
11/20/2004	Sat	Winter	-	57.55	44.28	4.90	11,748	9,039	10,845
11/21/2004	Sun	Winter	-		46.04	4.90		9,399	9,399
11/22/2004	Mon	Winter	-	51.97	46.04	4.90	10,609	9,399	10,206
11/23/2004	Tue	Winter	-	62.72	48.93	6.07	10,335	8,063	9,578
11/24/2004	Wed	Winter	-	62.72	48.93	5.98	10,494	8,186	9,724
11/25/2004	Thu	Winter	Holiday		50.59	5.67		8,924	8,924
11/26/2004	Fri	Winter	-	55.79	50.59	5.67	9,841	8,924	9,535
11/27/2004	Sat	Winter	-	55.79	50.59	5.67	9,841	8,924	9,535
11/28/2004	Sun	Winter	-		46.59	5.67		8,218	8,218
11/29/2004	Mon	Winter	-	54.19	46.59	5.67	9,558	8,218	9,112
11/30/2004	Tue	Winter	-	75.73	56.27	7.48	10,123	7,522	9,256
12/01/2004	Wed	Winter	-	77.60	59.14	7.24	10,723	8,172	9,872
12/02/2004	Thu	Winter	-	78.95	62.40	7.35	10,743	8,491	9,992
12/03/2004	Fri	Winter	-	69.11	52.16	7.00	9,871	7,450	9,064
12/04/2004	Sat	Winter	-	69.11	52.16	6.57	10,523	7,942	9,663
12/05/2004	Sun	Winter	-		57.17	6.57		8,705	8,705
12/06/2004	Mon	Winter	-	66.02	57.17	6.57	10,052	8,705	9,603
12/07/2004	Tue	Winter	-	68.04	53.65	6.66	10,211	8,052	9,491
12/08/2004	Wed	Winter	-	65.74	49.29	6.57	10,013	7,508	9,178
12/09/2004	Thu	Winter	-	63.33	48.75	6.26	10,116	7,787	9,340
12/10/2004	Fri	Winter	-	62.54	47.40	6.24	10,017	7,592	9,209
12/11/2004	Sat	Winter	-	62.54	47.40	6.31	9,916	7,516	9,116
12/12/2004	Sun	Winter	-		51.99	6.31		8,243	8,243
12/13/2004	Mon	Winter	-	65.32	51.99	6.31	10,357	8,243	9,653
12/14/2004	Tue	Winter	-	67.64	50.42	6.66	10,151	7,567	9,290
12/15/2004	Wed	Winter	-	67.91	50.52	6.87	9,883	7,352	9,039
12/16/2004	Thu	Winter	-	64.51	46.35	6.73	9,582	6,885	8,683
12/17/2004	Fri	Winter	-	60.98	42.94	6.64	9,178	6,463	8,273
12/18/2004	Sat	Winter	-	60.98	42.94	6.85	8,904	6,270	8,026
12/19/2004	Sun	Winter	-		51.14	6.85		7,467	7,467
12/20/2004	Mon	Winter	-	65.68	51.14	6.85	9,590	7,467	8,883
12/21/2004	Tue	Winter	-	63.36	46.20	6.80	9,317	6,794	8,476
12/22/2004	Wed	Winter	-	63.36	46.20	6.58	9,625	7,018	8,756
12/23/2004	Thu	Winter	-	59.06	46.36	6.72	8,790	6,900	8,160
12/24/2004	Fri	Winter	-	59.06	46.36	6.54	9,034	7,091	8,386
12/25/2004	Sat	Winter	Holiday		46.36	6.54		7,091	7,091

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
12/26/2004	Sun	Winter	-		50.10	6.54		7,663	7,663
12/27/2004	Mon	Winter	-	63.17	50.10	6.54	9,662	7,663	8,996
12/28/2004	Tue	Winter	-	58.12	44.26	6.25	9,294	7,078	8,556
12/29/2004	Wed	Winter	-	58.12	44.26	6.00	9,681	7,372	8,911
12/30/2004	Thu	Winter	-	53.55	40.25	6.06	8,836	6,641	8,104
12/31/2004	Fri	Winter	-	53.55	40.25	6.06	8,836	6,641	8,104
01/01/2005	Sat	Winter	Holiday		44.37	5.98		7,416	7,416
01/02/2005	Sun	Winter	-		45.55	5.98		7,613	7,613
01/03/2005	Mon	Winter	-	55.79	45.55	5.98	9,325	7,613	8,754
01/04/2005	Tue	Winter	-	54.90	39.63	5.63	9,749	7,037	8,845
01/05/2005	Wed	Winter	-	61.49	45.37	5.82	10,561	7,792	9,638
01/06/2005	Thu	Winter	-	65.72	47.44	5.99	10,970	7,919	9,953
01/07/2005	Fri	Winter	-	60.03	43.68	5.87	10,230	7,444	9,301
01/08/2005	Sat	Winter	-	60.03	43.68	5.98	10,032	7,300	9,121
01/09/2005	Sun	Winter	-		45.54	5.98		7,611	7,611
01/10/2005	Mon	Winter	-	60.13	45.54	5.98	10,049	7,611	9,236
01/11/2005	Tue	Winter	-	61.53	41.59	6.20	9,919	6,704	8,847
01/12/2005	Wed	Winter	-	58.81	40.86	5.97	9,845	6,840	8,844
01/13/2005	Thu	Winter	-	58.81	40.86	5.95	9,881	6,865	8,875
01/14/2005	Fri	Winter	-	56.80	39.85	6.00	9,467	6,642	8,525
01/15/2005	Sat	Winter	-	56.80	39.85	6.37	8,919	6,257	8,031
01/16/2005	Sun	Winter	-		47.17	6.37		7,407	7,407
01/17/2005	Mon	Winter	-	60.20	47.17	6.37	9,452	7,407	8,770
01/18/2005	Tue	Winter	-	60.10	43.02	6.37	9,437	6,755	8,543
01/19/2005	Wed	Winter	-	58.51	39.93	6.37	9,181	6,265	8,209
01/20/2005	Thu	Winter	-	54.75	37.54	5.94	9,219	6,321	8,253
01/21/2005	Fri	Winter	-	54.26	37.25	6.00	9,043	6,208	8,098
01/22/2005	Sat	Winter	-	54.26	37.25	6.23	8,714	5,982	7,804
01/23/2005	Sun	Winter	-		43.25	6.23		6,946	6,946
01/24/2005	Mon	Winter	-	57.92	43.25	6.23	9,302	6,946	8,517
01/25/2005	Tue	Winter	-	55.54	36.71	6.16	9,023	5,964	8,004
01/26/2005	Wed	Winter	-	54.57	36.36	6.15	8,870	5,910	7,883
01/27/2005	Thu	Winter	-	52.24	36.03	6.16	8,487	5,853	7,609
01/28/2005	Fri	Winter	-	50.79	35.40	6.20	8,192	5,710	7,365
01/29/2005	Sat	Winter	-	50.79	35.40	6.04	8,413	5,864	7,563
01/30/2005	Sun	Winter	-		42.28	6.04		7,003	7,003
01/31/2005	Mon	Winter	-	52.79	42.28	6.04	8,744	7,003	8,164
02/01/2005	Tue	Winter	-	53.33	37.67	5.98	8,915	6,297	8,043
02/02/2005	Wed	Winter	-	54.48	39.89	6.17	8,828	6,464	8,040
02/03/2005	Thu	Winter	-	54.29	41.13	6.20	8,762	6,638	8,054
02/04/2005	Fri	Winter	-	51.00	40.60	6.17	8,272	6,585	7,710
02/05/2005	Sat	Winter	-	51.00	40.60	6.02	8,466	6,740	7,891
02/06/2005	Sun	Winter	-		45.60	6.02		7,570	7,570
02/07/2005	Mon	Winter	-	54.34	45.60	6.02	9,021	7,570	8,537
02/08/2005	Tue	Winter	-	53.17	41.31	5.99	8,884	6,902	8,223
02/09/2005	Wed	Winter	-	53.39	42.85	5.97	8,947	7,181	8,358
02/10/2005	Thu	Winter	-	55.20	44.04	6.11	9,032	7,206	8,424
02/11/2005	Fri	Winter	-	52.45	42.09	6.06	8,656	6,946	8,086
02/12/2005	Sat	Winter	-	52.45	42.09	5.96	8,800	7,061	8,220

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
02/13/2005	Sun	Winter	-		45.52	5.96		7,637	7,637
02/14/2005	Mon	Winter	-	52.81	45.52	5.96	8,860	7,637	8,452
02/15/2005	Tue	Winter	-	51.86	40.04	5.95	8,717	6,731	8,055
02/16/2005	Wed	Winter	-	53.34	40.47	6.00	8,896	6,749	8,180
02/17/2005	Thu	Winter	-	53.34	40.47	6.05	8,813	6,687	8,104
02/18/2005	Fri	Winter	-	52.93	40.15	6.02	8,798	6,674	8,090
02/19/2005	Sat	Winter	-	52.93	40.15	5.86	9,038	6,855	8,310
02/20/2005	Sun	Winter	-		45.57	5.86		7,781	7,781
02/21/2005	Mon	Winter	Holiday		45.57	5.86		7,781	7,781
02/22/2005	Tue	Winter	-	53.06	40.73	5.86	9,060	6,954	8,358
02/23/2005	Wed	Winter	-	52.97	38.89	5.93	8,940	6,563	8,148
02/24/2005	Thu	Winter	-	52.80	39.31	5.97	8,838	6,580	8,086
02/25/2005	Fri	Winter	-	54.06	40.25	6.29	8,599	6,402	7,867
02/26/2005	Sat	Winter	-	54.06	40.25	6.23	8,674	6,458	7,936
02/27/2005	Sun	Winter	-		44.04	6.23		7,067	7,067
02/28/2005	Mon	Winter	-	53.86	44.04	6.23	8,642	7,067	8,117
03/01/2005	Tue	Winter	-	56.86	41.08	6.61	8,600	6,213	7,804
03/02/2005	Wed	Winter	-	56.11	39.25	6.54	8,584	6,005	7,724
03/03/2005	Thu	Winter	-	54.87	39.00	6.48	8,462	6,014	7,646
03/04/2005	Fri	Winter	-	54.81	39.47	6.70	8,183	5,893	7,419
03/05/2005	Sat	Winter	-	54.81	39.47	6.48	8,459	6,091	7,670
03/06/2005	Sun	Winter	-		44.36	6.48		6,846	6,846
03/07/2005	Mon	Winter	-	55.06	44.36	6.48	8,497	6,846	7,947
03/08/2005	Tue	Winter	-	55.22	40.23	6.55	8,436	6,146	7,673
03/09/2005	Wed	Winter	-	55.66	41.50	6.62	8,402	6,265	7,690
03/10/2005	Thu	Winter	-	57.54	42.26	6.84	8,410	6,176	7,665
03/11/2005	Fri	Winter	-	55.23	40.47	6.67	8,286	6,072	7,548
03/12/2005	Sat	Winter	-	55.23	40.47	6.46	8,550	6,265	7,789
03/13/2005	Sun	Winter	-		43.43	6.46		6,724	6,724
03/14/2005	Mon	Winter	-	55.18	43.43	6.46	8,543	6,724	7,936
03/15/2005	Tue	Winter	-	55.46	40.59	6.74	8,229	6,022	7,493
03/16/2005	Wed	Winter	-	57.87	41.97	7.11	8,143	5,905	7,397
03/17/2005	Thu	Winter	-	56.98	41.18	7.09	8,033	5,806	7,291
03/18/2005	Fri	Winter	-	57.24	41.15	7.24	7,902	5,681	7,161
03/19/2005	Sat	Winter	-	57.24	41.15	7.08	8,085	5,812	7,327
03/20/2005	Sun	Winter	-		45.81	7.08		6,470	6,470
03/21/2005	Mon	Winter	-	57.95	45.81	7.08	8,185	6,470	7,613
03/22/2005	Tue	Winter	-	58.29	41.25	7.19	8,103	5,735	7,314
03/23/2005	Wed	Winter	-	58.37	41.47	7.31	7,982	5,671	7,212
03/24/2005	Thu	Winter	-	58.37	41.47	7.21	8,098	5,753	7,316
03/25/2005	Fri	Winter	-	56.39	42.76	7.19	7,843	5,947	7,211
03/26/2005	Sat	Winter	-	56.39	42.76	7.19	7,843	5,947	7,211
03/27/2005	Sun	Winter	-		49.39	7.19		6,869	6,869
03/28/2005	Mon	Winter	-	60.09	49.39	7.19	8,357	6,869	7,861
03/29/2005	Tue	Winter	-	58.90	43.19	6.99	8,431	6,183	7,682
03/30/2005	Wed	Winter	-	58.61	42.40	6.95	8,431	6,099	7,654
03/31/2005	Thu	Winter	-	58.00	41.57	7.20	8,054	5,773	7,294
04/01/2005	Fri	Winter	-	57.30	42.26	7.35	7,799	5,752	7,117
04/02/2005	Sat	Winter	-	57.30	42.26	7.25	7,898	5,825	7,207

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
04/03/2005	Sun	Winter	-		48.55	7.25		6,692	6,692
04/04/2005	Mon	Winter	-	59.58	48.55	7.25	8,213	6,692	7,706
04/05/2005	Tue	Winter	-	61.28	44.89	7.52	8,152	5,971	7,425
04/06/2005	Wed	Winter	-	59.40	44.19	7.19	8,256	6,142	7,552
04/07/2005	Thu	Winter	-	60.63	45.37	7.23	8,390	6,278	7,686
04/08/2005	Fri	Winter	-	58.61	44.89	7.39	7,931	6,075	7,312
04/09/2005	Sat	Winter	-	58.61	44.89	7.14	8,204	6,284	7,564
04/10/2005	Sun	Winter	-		49.80	7.14		6,971	6,971
04/11/2005	Mon	Winter	-	59.19	49.80	7.14	8,285	6,971	7,847
04/12/2005	Tue	Winter	-	59.31	44.15	7.06	8,396	6,250	7,681
04/13/2005	Wed	Winter	-	60.93	44.40	7.25	8,405	6,125	7,645
04/14/2005	Thu	Winter	-	59.92	43.84	7.02	8,541	6,249	7,777
04/15/2005	Fri	Winter	-	59.96	44.48	6.95	8,628	6,400	7,885
04/16/2005	Sat	Winter	-	59.96	44.48	6.87	8,734	6,479	7,982
04/17/2005	Sun	Winter	-		51.54	6.87		7,508	7,508
04/18/2005	Mon	Winter	-	61.90	51.54	6.87	9,017	7,508	8,514
04/19/2005	Tue	Winter	-	61.04	44.21	6.88	8,867	6,422	8,052
04/20/2005	Wed	Winter	-	60.36	43.07	6.95	8,682	6,195	7,853
04/21/2005	Thu	Winter	-	59.81	44.19	6.97	8,581	6,340	7,834
04/22/2005	Fri	Winter	-	57.68	42.96	6.77	8,522	6,347	7,797
04/23/2005	Sat	Winter	-	57.68	42.96	6.82	8,460	6,301	7,741
04/24/2005	Sun	Winter	-		49.44	6.82		7,252	7,252
04/25/2005	Mon	Winter	-	58.76	49.44	6.82	8,619	7,252	8,163
04/26/2005	Tue	Winter	-	59.05	43.25	7.07	8,357	6,121	7,612
04/27/2005	Wed	Winter	-	59.05	43.25	6.93	8,517	6,238	7,757
04/28/2005	Thu	Winter	-	59.05	43.25	7.01	8,429	6,174	7,677
04/29/2005	Fri	Winter	-	50.84	37.93	6.58	7,732	5,768	7,077
04/30/2005	Sat	Winter	-	50.84	37.93	6.58	7,732	5,768	7,077
05/01/2005	Sun	Summer	-		42.53	6.50		6,541	6,541
05/02/2005	Mon	Summer	-	53.68	42.53	6.50	8,256	6,541	7,684
05/03/2005	Tue	Summer	-	51.76	34.99	6.27	8,251	5,578	7,360
05/04/2005	Wed	Summer	-	54.01	36.51	6.45	8,377	5,663	7,472
05/05/2005	Thu	Summer	-	53.47	38.95	6.37	8,398	6,117	7,638
05/06/2005	Fri	Summer	-	52.48	40.84	6.57	7,991	6,218	7,400
05/07/2005	Sat	Summer	-	52.48	40.84	6.49	8,091	6,296	7,493
05/08/2005	Sun	Summer	-		45.93	6.49		7,081	7,081
05/09/2005	Mon	Summer	-	55.17	45.93	6.49	8,506	7,081	8,031
05/10/2005	Tue	Summer	-	54.48	37.96	6.49	8,392	5,848	7,544
05/11/2005	Wed	Summer	-	53.87	35.21	6.53	8,254	5,395	7,301
05/12/2005	Thu	Summer	-	51.98	31.27	6.43	8,085	4,864	7,011
05/13/2005	Fri	Summer	-	48.62	24.46	6.38	7,617	3,832	6,355
05/14/2005	Sat	Summer	-	48.62	24.46	6.10	7,968	4,008	6,648
05/15/2005	Sun	Summer	-		35.78	6.10		5,864	5,864
05/16/2005	Mon	Summer	-	52.26	35.78	6.10	8,564	5,864	7,664
05/17/2005	Tue	Summer	-	51.28	32.84	6.18	8,298	5,314	7,304
05/18/2005	Wed	Summer	-	48.37	29.92	6.06	7,980	4,936	6,966
05/19/2005	Thu	Summer	-	44.56	15.64	6.16	7,235	2,539	5,670
05/20/2005	Fri	Summer	-	44.44	14.06	5.96	7,452	2,358	5,754
05/21/2005	Sat	Summer	-	44.44	14.06	5.83	7,618	2,410	5,882

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
05/22/2005	Sun	Summer	-		40.65	5.83		6,968	6,968
05/23/2005	Mon	Summer	-	57.90	40.65	5.83	9,925	6,968	8,940
05/24/2005	Tue	Summer	-	56.58	18.15	5.98	9,456	3,033	7,315
05/25/2005	Wed	Summer	-	54.04	16.83	6.08	8,892	2,769	6,851
05/26/2005	Thu	Summer	-	54.04	16.83	6.04	8,947	2,787	6,894
05/27/2005	Fri	Summer	-	48.41	15.35	5.99	8,080	2,562	6,240
05/28/2005	Sat	Summer	-	48.41	15.35	5.84	8,294	2,630	6,406
05/29/2005	Sun	Summer	-		35.28	5.84		6,044	6,044
05/30/2005	Mon	Summer	Holiday		35.28	5.84		6,044	6,044
05/31/2005	Tue	Summer	-	47.89	16.21	5.84	8,205	2,777	6,396
06/01/2005	Wed	Summer	-	47.63	19.84	5.99	7,948	3,311	6,402
06/02/2005	Thu	Summer	-	46.34	22.46	5.95	7,788	3,774	6,450
06/03/2005	Fri	Summer	-	45.38	22.31	6.07	7,481	3,678	6,213
06/04/2005	Sat	Summer	-	45.38	22.31	5.87	7,735	3,802	6,424
06/05/2005	Sun	Summer	-		29.95	5.87		5,105	5,105
06/06/2005	Mon	Summer	-	42.58	29.95	5.87	7,257	5,105	6,540
06/07/2005	Tue	Summer	-	44.42	19.10	6.54	6,791	2,920	5,501
06/08/2005	Wed	Summer	-	44.86	22.74	6.42	6,983	3,540	5,835
06/09/2005	Thu	Summer	-	49.26	24.11	6.42	7,675	3,757	6,369
06/10/2005	Fri	Summer	-	47.65	24.80	6.30	7,561	3,935	6,352
06/11/2005	Sat	Summer	-	47.65	24.80	6.22	7,655	3,984	6,431
06/12/2005	Sun	Summer	-		39.63	6.22		6,366	6,366
06/13/2005	Mon	Summer	-	55.66	39.63	6.22	8,942	6,366	8,083
06/14/2005	Tue	Summer	-	56.52	28.22	6.38	8,864	4,426	7,384
06/15/2005	Wed	Summer	-	55.62	29.26	6.46	8,617	4,533	7,255
06/16/2005	Thu	Summer	-	47.77	32.82	6.36	7,511	5,161	6,728
06/17/2005	Fri	Summer	-	47.01	31.63	6.38	7,366	4,956	6,563
06/18/2005	Sat	Summer	-	47.01	31.63	6.48	7,254	4,881	6,463
06/19/2005	Sun	Summer	-		39.13	6.48		6,038	6,038
06/20/2005	Mon	Summer	-	54.88	39.13	6.48	8,468	6,038	7,658
06/21/2005	Tue	Summer	-	60.98	36.32	6.84	8,913	5,309	7,711
06/22/2005	Wed	Summer	-	59.66	36.61	6.68	8,935	5,483	7,784
06/23/2005	Thu	Summer	-	61.76	38.45	6.72	9,189	5,721	8,033
06/24/2005	Fri	Summer	-	59.22	38.31	6.79	8,725	5,644	7,698
06/25/2005	Sat	Summer	-	59.22	38.31	6.65	8,899	5,757	7,852
06/26/2005	Sun	Summer	-		40.69	6.65		6,114	6,114
06/27/2005	Mon	Summer	-	57.32	40.69	6.65	8,613	6,114	7,780
06/28/2005	Tue	Summer	-	55.17	29.81	6.54	8,437	4,559	7,144
06/29/2005	Wed	Summer	-	58.75	29.39	6.29	9,344	4,675	7,788
06/30/2005	Thu	Summer	-	58.75	29.39	6.28	9,362	4,683	7,802
07/01/2005	Fri	Summer	-	56.89	28.31	6.37	8,938	4,448	7,441
07/02/2005	Sat	Summer	-	56.89	28.31	6.13	9,284	4,620	7,730
07/03/2005	Sun	Summer	-		42.53	6.13		6,941	6,941
07/04/2005	Mon	Summer	Holiday		42.53	6.13		6,941	6,941
07/05/2005	Tue	Summer	-	59.39	28.88	6.13	9,692	4,713	8,033
07/06/2005	Wed	Summer	-	65.74	35.78	6.89	9,546	5,196	8,096
07/07/2005	Thu	Summer	-	69.73	44.45	6.96	10,012	6,382	8,802
07/08/2005	Fri	Summer	-	62.68	41.50	6.79	9,233	6,113	8,193
07/09/2005	Sat	Summer	-	62.68	41.50	6.66	9,416	6,234	8,355

Date	Weekday	Season	Holiday	NP15 On Peak Cost	NP15 Off Peak Cost	PGE City Gate	On Peak Implicit Heat Rate	Off Peak Implicit Heat Rate	Daily Implicit Heat Rate
07/10/2005	Sun	Summer	-		46.62	6.66		7,003	7,003
07/11/2005	Mon	Summer	-	68.29	46.62	6.66	10,259	7,003	9,174
07/12/2005	Tue	Summer	-	74.92	43.45	6.66	11,243	6,521	9,669
07/13/2005	Wed	Summer	-	78.39	40.40	6.99	11,213	5,779	9,401
07/14/2005	Thu	Summer	-	75.14	40.25	6.98	10,769	5,769	9,102
07/15/2005	Fri	Summer	-	74.49	42.60	7.34	10,154	5,807	8,705
07/16/2005	Sat	Summer	-	74.49	42.60	7.18	10,371	5,931	8,891
07/17/2005	Sun	Summer	-		56.25	7.18		7,832	7,832
07/18/2005	Mon	Summer	-	87.24	56.25	7.18	12,147	7,832	10,708
07/19/2005	Tue	Summer	-	101.80	51.18	7.07	14,401	7,240	12,014
07/20/2005	Wed	Summer	-	98.41	48.47	6.89	14,275	7,031	11,860
07/21/2005	Thu	Summer	-	89.45	44.76	6.89	12,976	6,493	10,815
07/22/2005	Fri	Summer	-	75.51	46.64	6.82	11,065	6,834	9,655
07/23/2005	Sat	Summer	-	75.51	46.64	6.60	11,438	7,065	9,981
07/24/2005	Sun	Summer	-		58.81	6.60		8,909	8,909
07/25/2005	Mon	Summer	-	76.31	58.81	6.60	11,559	8,909	10,676
07/26/2005	Tue	Summer	-	71.15	43.88	6.53	10,903	6,724	9,510
07/27/2005	Wed	Summer	-	69.71	43.81	6.57	10,608	6,666	9,294
07/28/2005	Thu	Summer	-	69.71	43.81	6.68	10,436	6,559	9,144
07/29/2005	Fri	Summer	-	66.50	42.24	6.68	9,950	6,320	8,740
07/30/2005	Sat	Summer	-	66.50	42.24	6.68	9,950	6,320	8,740
07/31/2005	Sun	Summer	-		59.33	6.68		8,877	8,877

Appendix B

Combustion Turbine Costs

Fixed Costs

In its most recent marginal cost filing, PG&E used a combustion turbine cost of $80/kW (2004 dollars), with variable O&M costs of $15.83/MWh and a heat rate of 9300 Btu/kWh. All of these figures come from CEC data.

TURN believes that, with all due respect to the CEC, the figures are inaccurate in a number of respects and should generally be reduced (though the heat rate is actually too low). There are several egregious errors in input assumptions.

First, it is simply wrong to use the CEC's $80 capacity cost figure without adjustment. The calculation mixes real and nominal dollars and is a fundamental error from the perspective of marginal and avoided cost theory. The CEC's capital and fixed O&M cost figures are in levelized nominal dollars over a 20 year period. This creates a fundamental mismatch with the energy costs (which are a single year's dollars).

The Commission has calculated marginal capacity costs and single-year avoided capacity costs in real terms for over 20 years, since the OIR 2 decision (D. 82-12-120) and 1983 Test Year Edison General Rate Case (D. 82-12-055). Levelized nominal dollar capacity costs have never been used before for either marginal or avoided costs since then.

Second, the model should be run assuming utility financing for computing avoided cost.

However, once I tried to run the CEC's model using utility financing, I found that while the CEC modelers built a model that was largely reasonable for merchant financing, they had no understanding of utility ratemaking and made such large mistakes in utility accounting that the model is simply and irretrievably wrong for computing IOU costs for the following reasons (even though it appears to work properly for computing merchant plant costs).

1. The model double-counts the income tax deduction for book depreciation by taking book depreciation as a tax deduction and then taking the entire amount of tax depreciation as a second tax deduction, thus understating income taxes.

2. The model uses flow-through tax accounting even though federal taxes are normalized.

3. The whole loan repayment and equity return model used by the CEC, while appropriate for a merchant plant, does not fit utility accounting at all. The CEC model uses mortgage amortization for the debt portion of capitalization and assumes a flat equity return in all years. This is counter to the rate-base and rate of return regulation, where the amount of both equity and debt decline over time because they are based on gross plant, less accumulated depreciation, less deferred taxes.

4. The model includes in the cash flow both book depreciation and principal repayments, thus double-counting any principal repayments (which would be made from money received from book depreciation).[12]

5. The CEC used the wrong federal and state tax depreciation parameters. There appears to be a transposition error, as the CEC used 20-year federal tax depreciation and 15-year state tax depreciation. According to SDG&E's RAMCO application,[13] a CT is depreciated for federal tax purposes over 15 years, not 20 and for state purposes over 20 years, not 15.

6. The CEC made a technical error in the computation of property taxes for a plant owned by the utility. A utility's property taxes are based on net plant minus deferred taxes, not on gross plant.

Because the CEC built an incorrect and inadequate model to analyze utility ownership of a power plant, I used the JBS Energy, Inc. fixed charge model to compute the combustion turbine fixed costs. This model has been used to analyze utility plant investments for over 20 years in many North American jurisdictions. I added 10% to the CEC's capital cost (2004 dollars) for conservatism, updated the model to include the impact of the 2004 tax act's gross revenue credit for generation and used PG&E's 2005 capital structure and costs from A. 04-05-023 (as adopted by the Commission) instead of theoretical data used by the CEC for utility projects as representative of the marginal cost of capital given PG&E's recent issuance of new debt of a variety of maturities.

[12] This is not a problem in the merchant plant model, which does not include book depreciation.

[13] J. Van Lierop, Supplemental Testimony on behalf of SDG&E in R. 01-01-024 (Ramco and Palomar phase), page JVL-14.

I used two additional assumptions that are different from CEC assumptions in computing fixed charges for capacity and O&M.[14]

1. I used a 25-year book and economic life for the combustion turbine. SDG&E's RAMCO CT has a 25 year depreciable life – not the 20 years assumed by the CEC model.[15]

2. The CEC assumes exorbitant insurance costs of 1.5% of the capital cost in the first year escalating with inflation. Estimates from sources as disparate as the Northwest Power Planning Council (0.25%)[16] and Southern California Edison Company (0.11%)[17] suggest insurance costs in the range of 0.1% to 0.25% of capital cost for a large entity building a new power plant. We recommend that the Commission use 0.25% of the capital cost for conservatism.

Table B-1 shows the input assumptions and Table B-2 shows the results.

Table B-1 CT input assumptions

INPUT ASSUMPTIONS			
TYPE OF PLANT	Combustion Turbine		
UTILITY NAME	PG&E		
TYPE OF UTILITY	IOU Regulated		
REFERENCE YEAR		2004	
INFLATION RATE		2.5%	
NET SALVAGE		0.0%	
BOOK LIFE		25.00	YEARS
DEPRECIATION % PER YEAR			
DISCOUNT RATE	8.70%		
RETURN	8.70%		
DEBT	5.94%	45.5%	
COMMON	11.22%	52.0%	
PREFERRED	6.42%	2.5%	
FED INCOME TAX		35.0%	
STATE INCOME TAX		8.8%	
PROPERTY TAX		1.1%	
INITIAL INVESTMENT ($/kW)		$523	
Capital Additions % of initial capital		0.00%	

[14] I used the same assumptions as the CEC for labor costs, but the CEC model computed a figure of $6.91/kW for fixed O&M in the first year, not the $9.81 included in its report.

[15] Van Lierop, op. cit., page JVL-10.

[16] Northwest Power Planning and Conservation Council, Fifth Draft Plan, Appendix I, page I-2 (0.25%);
http://www.nwppc.org/energy/powerplan/draftplan/Appendix%20I%20(Generating%20Resources)%20(PP).pdf

[17] Southern California Edison Company, Reply Comments on Proposed Decision, CPUC App. 03-07-032, December 15, 2003, Appendix B ($0.8 million insurance costs in 2007), Appendix A ($703.2 million capital cost)

Table B-2 CT Fixed Charge Model Run

	CALCULATED FIGURES																	
	LEVELIZED NOMINAL FIXED CHARGE RATE						12.41%		64.85	per kW								
	REAL FIXED CHARGE RATE						9.94%		51.93	per kW	escalating with inflation							
	COLUMNS 2 THROUGH 12 GIVE FIGURES PER THOUSAND DOLLARS INVESTED																	
1	2	3	4	5	6	7	8	9	10	10A	11	12	13	14	15	16	17	18
Year	Deprec. Book	Net Plant	Deprec. Fed. Tax.	Deferred Taxes	Deprec. State Tax	Flow-thru depreciation (state)	Rate Base	Return	Income Taxes (current)	Additional impact of 2004 tax act	Property Taxes	Fixed Rev. Req. Per 1000	Fixed Rev. Req. Per kW	Real Fixed Charge per $1000	Real Fixed Charge per kW	Insurance 0.25%	Fixed O&M	Total Marginal CT Cost
2004	40.00	980.00	50.00	3.50	37.52	-0.14	978.25	85.08	40.47	0.00	10.76	176.31	92.12	99.40	51.93	1.31	7.70	60.94
2005	40.00	940.00	95.00	19.25	68.88	1.66	926.88	80.62	36.55	-0.98	10.20	166.38	86.93	101.88	53.23	1.34	7.94	62.51
2006	40.00	900.00	85.50	15.93	63.96	1.38	869.29	75.61	34.46	-0.94	9.56	158.69	82.92	104.43	54.56	1.37	8.19	64.13
2007	40.00	860.00	77.00	12.95	59.39	1.11	814.85	70.87	32.48	-1.78	8.96	150.53	78.65	107.04	55.93	1.41	8.45	65.78
2008	40.00	820.00	69.30	10.26	55.15	0.87	763.25	66.38	30.59	-1.70	8.40	143.68	75.07	109.71	57.33	1.44	8.71	67.47
2009	40.00	780.00	62.30	7.81	51.21	0.64	714.22	62.12	28.80	-2.42	7.86	136.36	71.25	112.46	58.76	1.48	8.97	69.21
2010	40.00	740.00	59.00	6.65	47.55	0.43	666.99	58.01	27.06		7.34	132.41	69.18	115.27	60.23	1.51	9.25	70.99
2011	40.00	700.00	59.00	6.65	44.16	0.24	620.34	53.95	25.33		6.82	126.11	65.89	118.15	61.73	1.55	9.53	72.82
2012	40.00	660.00	59.10	6.69	41.00	0.06	573.67	49.90	23.59		6.31	119.80	62.59	121.10	63.28	1.59	9.82	74.69
2013	40.00	620.00	59.00	6.65	38.07	-0.11	527.01	45.84	21.84		5.80	113.47	59.29	124.13	64.86	1.63	10.11	76.60
2014	40.00	580.00	59.10	6.69	35.35	-0.27	480.34	41.78	20.07		5.28	107.13	55.98	127.23	66.48	1.67	10.42	78.57
2015	40.00	540.00	59.00	6.65	32.83	-0.41	433.67	37.72	18.29		4.77	100.78	52.66	130.41	68.14	1.71	10.73	80.58
2016	40.00	500.00	59.10	6.69	30.48	-0.55	387.00	33.66	16.50		4.26	94.42	49.33	133.68	69.85	1.76	11.05	82.65
2017	40.00	460.00	59.00	6.65	28.30	-0.67	340.34	29.60	14.70		3.74	88.05	46.00	137.02	71.59	1.80	11.37	84.76
2018	40.00	420.00	59.10	6.69	26.28	-0.79	293.67	25.54	12.89		3.23	81.67	42.67	140.44	73.38	1.85	11.71	86.93
2019	40.00	380.00	29.50	-3.68	25.31	-0.84	252.16	21.93	11.24		2.77	75.95	39.68	143.95	75.22	1.89	12.05	89.16
2020	40.00	340.00	0.00	-14.00	25.31	-0.84	221.00	19.22	9.95		2.43	71.61	37.41	147.55	77.10	1.94	12.40	91.43
2021	40.00	300.00	0.00	-14.00	25.31	-0.84	195.00	16.96	8.88		2.15	67.99	35.52	151.24	79.02	1.99	12.76	93.77
2022	40.00	260.00	0.00	-14.00	25.31	-0.84	169.00	14.70	7.81		1.86	64.37	33.63	155.02	81.00	2.04	13.13	96.17
2023	40.00	220.00	0.00	-14.00	25.31	-0.84	143.00	12.44	6.74		1.57	60.75	31.74	158.90	83.02	2.09	13.51	98.62
2024	40.00	180.00	0.00	-14.00	0.00	-2.30	117.00	10.18	7.12		1.29	58.58	30.61	162.87	85.10	2.14	13.89	101.13
2025	40.00	140.00	0.00	-14.00	0.00	-2.30	91.00	7.91	6.05		1.00	54.97	28.72	166.94	87.23	2.19	14.29	103.71
2026	40.00	100.00	0.00	-14.00	0.00	-2.30	65.00	5.65	4.98		0.71	51.35	26.83	171.12	89.41	2.25	14.70	106.36
2027	40.00	60.00	0.00	-14.00	0.00	-2.30	39.00	3.39	3.91		0.43	47.73	24.94	175.39	91.64	2.31	15.12	109.06
2028	40.00	20.00	0.00	-14.00	0.00	-2.30	13.00	1.13	2.83		0.14	44.11	23.05	179.78	93.93	2.36	15.54	111.84
NPV											67.04	1249.64	652.93	1249.49	652.86	16.42	101.55	770.83
Levelized Nominal													64.85		64.84	1.63	10.09	76.56

The end result was a levelized nominal dollar cost of $76.75 per kW but a 2004 dollar avoided cost (using an economic carrying charge and first year values for O&M and insurance) year rate of $60.95. The difference between the CEC's $80 and $76.75 is due to modeling conventions and assumptions, and the difference between $60.95 and $76.75 is due to the use of real dollars and an economic carrying charge rate consistent with marginal and avoided cost theory instead of nominal dollars.

CT Variable Costs for Use in Computing Capped Energy Price

The CEC's fuel costs are too low, not because the CEC's heat rate is incorrect, but because it is incomplete. The CEC's heat rate of 9300 Btu/kWh is too low because it is based on full load operations, without any allowance for fuel consumed in ramp-ups, extra fuel consumed under hot weather conditions when the turbine is more likely to operate, and amortizing the fuel consumed during start-ups (identified in the CEC model as 1800 Btu per kW per start) over the operational period. A heat rate of 10,000 Btu/kWh would be more consistent with actual operations rather than full load without ramping, start-ups, or temperatures above 59 degrees. Such a figure is generally consistent with the CDWR combustion turbine contracts.

More importantly, I believe that the CEC has significantly overstated variable O&M costs for a simple cycle combustion turbine. The CEC model estimates a cost of almost $16/MWh (2004 dollars). The CEC's variable O&M costs are too high (well above CDWR variable O&M contracts of $3 to $12 per MWh) because the CEC:

a. Amortized the cost of replacement of an undefined piece of air emissions equipment and another unidentified piece of water quality equipment that is supposed to last over 141,000 hours over 15 years, even though a peaking CT will run only about a tenth as many hours in that time period as the 141,000 hour alleged life of the unidentified equipment.

b. Assumed that a 100 MW CT's water use will be one-fifth that of a 500 MW combined cycle without any adjustment for the 10% capacity factor of the CT versus the 91% capacity factor of the combined cycle, thus calculating water costs per MWh that are almost 10 times that of a combined cycle. I scaled water use to MWh production, not megawatts of capacity.

c. Assumed the same $375,000 of parts was needed to repair forced outages for a 500 MW combined cycle as a 100 MW combustion turbine with about 10% as many forced outage hours. I reduced the figure proportionately to megawatts to $75,000.

d. Assumed annual NOX catalyst costs and water treatment consumables costs that are 10% as much for a 100 MW CT as a 500 MW CC even though the CT generates only 2% as much energy as the baseload CC. We assumed that consumables costs were twice as expensive per MWh for the CT as the CC, not 5 times as expensive.

Recalculating the variable O&M costs for these four items yields a first year variable O&M expense of $7.87/MWh (2004 dollars) compared to the CEC's $15.83. This figure is much more in the range of recent commercial contracts than the CEC's figure. For conservatism, I recommend $10/MWh (2006 dollars) for computing the capped energy price. This figure reflects that some O&M costs are actually start-up related even though treated as variable by the CEC model, and CTs have a fairly large number of starts).

The lower variable O&M costs would outweigh the higher heat rate, causing the CT to be dispatched more frequently.

Qualifications of William B. Marcus

William B. Marcus has 27 years of experience in analysis of electric and gas utilities.

Mr. Marcus graduated from Harvard College with an A.B. magna cum laude in economics in 1974 and was elected to Phi Beta Kappa. In 1975, he received an M.A. in economics from the University of Toronto.

In July 1984, Mr. Marcus became Principal Economist for JBS Energy, Inc. In this position, he is the company's lead economist for utility issues.

Mr. Marcus is the co-author of a book on electric restructuring prepared for the National Association of Regulatory Utility Commissioners. He wrote a major report on Performance Based Ratemaking for the Energy Foundation. He analyzed restructuring and stranded costs in eight states and provinces for environmental, consumer, and independent power clients.

Mr. Marcus has prepared testimony and formal comments submitted to the Federal Energy Regulatory Commission, the National Energy Board of Canada, the Bonneville Power Administration, the U.S. Bureau of Indian Affairs, U.S. District Court in San Diego, Nevada County Municipal Court, legislative committees in Ontario and California, the California Energy Commission (CEC), the Sacramento Municipal Utility District (SMUD), the Transmission Agency of Northern California, the State of Nevada's Colorado River Commission, environmental boards in Ontario, Manitoba, and Nova Scotia; and regulatory commissions in Alberta, Arizona, Arkansas, British Columbia, California, Colorado, Connecticut, District of Columbia, Hawaii, Manitoba, Maryland, Massachusetts, Nevada, New Jersey, New Mexico, North Carolina, Northwest Territories, Nova Scotia, Ohio, Oklahoma, Ontario, Oregon, South Carolina, Texas, Utah, Vermont, Virginia, Washington, Wisconsin, and Yukon. He testified on issues including utility restructuring, stranded costs, Performance-Based Ratemaking, resource planning, load forecasts, need for powerplants and transmission lines, environmental effects of electricity production, evaluation of conservation potential and programs, utility affiliate transactions, mergers, other revenue issues, avoided cost, and electric and gas cost of service and rate design.

From 1975 to 1978, Mr. Marcus was a research analyst at the Kennedy School of Government, Harvard University.

From July, 1978 through April, 1982, Mr. Marcus was an economist at the CEC, first in the energy development division and later as a senior economist in the CEC's Executive Office. He prepared testimony on purchased power pricing and economic studies of transmission projects, renewable resources, and conservation programs, and managed interventions in utility rate cases.

From April, 1982, through June, 1984, he was principal economist at California Hydro Systems, Inc., an alternative energy consulting and development company. He prepared financial analyses of projects, negotiated utility contracts, and provided consulting services on utility economics and resources.

Mr. Marcus served on the 1991-92 SMUD Rate Advisory Committee, which made cost allocation and rate design recommendations to the SMUD Board. He serves on advisory committees for Woodland Community College and the City of Woodland, California.