EXHIBIT 1

Gas Accord III Settlement Agreement

Gas Accord III
Settlement Agreement

August 27, 2004

Subject to Rule 51 of the CPUC Rules of Practice and Procedure, Rule 601 et seq. of the FERC Rules of Practice, Rule 408 of the Federal Rules of Evidence, and Section 1152 of the California Evidence Code

Gas Accord III Settlement Agreement

August 27, 2004

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Gas Accord III
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1. Introduction

1.1. Purpose

The purpose of this Gas Accord III Settlement Agreement ("Settlement Agreement" or "Settlement") is to resolve all the issues set for litigation in PG&E's Gas Transmission and Storage 2005 Rate Case – Application 04-03-021. This Settlement is also in response to Ordering Paragraph 6j in Decision 03-12-061 that requires PG&E to file "an application no later than February 4, 2005 proposing the kind of gas market structure and rates that PG&E's gas transmission and storage system should operate under [beginning in 2006] ... and how long the rates and such a structure should remain in place."

1.2. Gas Accord

Under this Settlement Agreement, the basic Gas Accord structure approved in D.97-08-055 remains in place for Northern California. This includes unbundled transmission and storage services. Backbone transmission service is provided via defined paths under firm or as-available tariffs. Storage services are also offered on a firm and as-available basis. This Settlement Agreement makes certain small modifications to the existing Gas Accord provisions, as most recently modified in D.03-12-061, in addition to implementing a backbone level end-use service as ordered in D.03-12-061. As in the Gas Accord, the rates determined by this Settlement Agreement reflect a negotiated balance including, among other things, cost-of-service, backbone load factor, local transmission throughput, and annual cost of service escalators.

1.3. Settlement Parties

This Settlement Agreement is entered into by the Settlement Parties ("Settlement Parties" or "Parties"), as identified by their attached signatures. Parties agree to actively support approval of this Settlement Agreement in A.04-03-021. Parties also agree to not support any changes to this Settlement Agreement that would be effective during the term of this Settlement in any regulatory, legislative or judicial forum, other than as allowed under this Settlement Agreement.

1.4. Tariffs To Implement Settlement

Simultaneously with the filing of this Settlement Agreement, PG&E agrees to file for Commission approval pro forma tariff sheets that would implement the terms agreed to herein. Parties request that the Commission approve the pro forma tariff sheets at the same time it approves the Settlement Agreement, and that the tariffs and rates be effective on January 1, 2005.

1.5. Tariffs Not Affected

Unless otherwise explicitly changed by this Settlement Agreement, all other portions of PG&E's tariffs related to providing gas transmission and storage services remain in place through 2007 for transmission and through March 31, 2008 for storage, unless changed by other Commission action.

1.6. Compromise and Support

This Settlement Agreement is a negotiated compromise of issues and is broadly supported by parties who are gas producers, marketers, shippers, independent storage providers, wholesale and retail end-use customers, and regulatory representatives. Nothing contained herein shall be deemed to constitute an admission or an acceptance by any party of any fact, principle, or position contained herein. Notwithstanding the foregoing, the Settlement Parties, by signing this Settlement Agreement and by joining the motion to adopt the Settlement Agreement filed before the Commission, acknowledge that they pledge support for Commission approval and subsequent implementation of these provisions.

1.7. Complete Package

This Settlement Agreement is to be treated as a complete package not as a collection of separate agreements on discrete issues or proceedings. To accommodate the interests of different parties on diverse issues, the Settlement Parties acknowledge that changes, concessions, or compromises by a party or parties in one section of this Settlement Agreement necessitated changes, concessions, or compromises by other parties in other sections.

1.8. Modifications by Commission

In the event the Commission rejects or modifies this Settlement Agreement, the Settlement Parties reserve their rights under Rule 51.7 of the Commission's Rules of Practice and Procedure.

1.9. Implementation

Within 12 days of a Commission decision approving this Settlement Agreement and the associated tariffs without modification, PG&E shall make a compliance filing to implement the rates and provisions of the Settlement.

2. Term of Settlement

2.1. Settlement Period

The Settlement covers three rate-case years (Settlement Period). The Settlement Period is January 1, 2005 through December 31, 2007, for transmission services, and April 1, 2005 through March 31, 2008, for storage services.

2.2. Next Rate Case Filing

2.2.1. PG&E will file its next rate case no later than February 9, 2007.

2.2.2. Should rates not be in place for Gas Transmission and Storage (GT&S) services by January 1, 2008, pursuant to an order in this next rate case, the interim transmission and storage rates will equal the rates in effect on December 31, 2007, plus a two (2) percent escalator and other adjustments authorized by this Settlement. G-XF rates continue to be calculated based on Line 401 incremental costs. These interim rates will remain in effect until the Commission otherwise approves rates for the remainder of 2008.

2.3. Effective Date

The effective date of this Settlement Agreement shall be the later of January 1, 2005, or the effective date of the tariffs approved by the Commission to implement the Settlement.

3. Transmission Services

3.1. Backbone Services

The path structure and backbone services remain the same. Except for the new backbone level end-use service, all gas transported using PG&E's backbone service must eventually be delivered to an on-system end user or wholesale customer using local transmission service, or to an off-system customer or delivery point.

3.1.1. Core Capacity Assignment and Vintage Capacity Allocation

PG&E's Core Procurement Department firm capacity assignments are as shown in Appendix A, Table A-1. Core Vintage Redwood firm capacity of 615.6 MDth/d (delivery capacity) is allocated to core retail and wholesale customers based on average-year January demands as shown in Appendix A, Table A-2.

Existing wholesale customers will have a one-time option prior to April 1, 2005, to subscribe to their allocation of Core Vintage Redwood firm capacity for the Settlement Period. This is the same one-time option previously available to wholesale customers under the Gas Accord.

During the Settlement Period, Core Procurement will meet and confer with ORA and TURN to discuss Core's firm storage and transportation needs.

3.1.2. Open Season

PG&E will not hold an open season for existing firm backbone capacity at the beginning of the Settlement Period. Sufficient firm backbone capacity remains available for any customer desiring this service at this time.

3.1.3. Commensurate Discount Rule

The commensurate discount rule will be removed from PG&E's tariffs once PG&E is no longer affiliated with Gas Transmission Northwest (GTN), the former Pacific Gas Transmission Company (PGT).

3.1.4. Mission-Off As-Available Rate for Storage Withdrawals

PG&E will revise its Mission-Off as-available tariff (G-AAOff) to allow any storage withdrawals delivered into PG&E's backbone system to be nominated for off-system delivery at no additional charge. Priority of as-available service for off-system deliveries will continue to be based on price. The rate design for firm Mission-Off service does not change.

3.1.5. Backbone Firm Contract Conversion Option to Accommodate Storage Withdrawals

Shippers may convert all or part of a firm on-system Redwood path contract exhibit or firm on-system Baja path contract exhibit for the purpose of transporting gas withdrawn from storage to a firm on-system Mission path contract exhibit at any time prior to 60 minutes before close of the Timely Cycle. For those shippers that convert to a firm on-system Mission path contract exhibit, PG&E will reduce the MDQ by an equal amount on their corresponding firm on-system Redwood or firm on-system Baja path contract exhibit for the same time period. Shippers will not be charged additional shrinkage or a volumetric rate for Mission path service, but will be responsible for the full monthly demand charge on their firm on-system Redwood path or firm on-system Baja path contract exhibit regardless of the amount of time the contract exhibit is converted to a firm on-system Mission path contract exhibit. On-system Baja path conversions will be limited to the amount of unsold firm Redwood capacity available at the time of the requested conversion. Firm Baja path conversions may be requested on a monthly basis, no more than 5 days prior to the end of the month, for a maximum term of one month. There is no limit to the maximum term for a firm Redwood path conversion.

3.2. Backbone Level End-Use Service

Backbone Level End-Use Service begins on the later of January 1, 2005, or the effective date of the tariff revisions required to implement this service. The eligibility criteria for this service are resolved for the term of this Settlement. Customers qualifying for this service do not pay the local transmission rate component as specified in the otherwise applicable end-use tariff. However, they continue to be responsible for all other rate components in their end-user tariffs to the extent they are not components of local transmission service, including, as applicable, the Customer Access Charge, Public Purpose Program Surcharge, Distribution Charge for G-EG Customers,[1] CPUC fee, franchise fees and

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1 These are the distribution costs allocated to distribution level electric generation customers taking service from G-EG. They will continue to be averaged in the rates of all end-use electric generation customers pursuant to Decision 03-12-061. The distribution rate is a separate rate component from the customer class charge. Parties are free to make proposals to de-average the distribution costs allocated to G-EG customers, in future proceedings such as BCAPs or GT&S Rate Case filings.

uncollectibles expense, G-SUR, Customer Class Charge, or other CPUC-mandated fees that may be implemented after this Settlement is finalized.

3.2.1. <u>Backbone Level End-Use Service Eligibility Requirements</u>

Backbone level end-use service eligibility is based on the criteria filed in PG&E's testimony in A.04-03-021.

3.2.1.1. The load must be new or incremental to PG&E's system (i.e., a new or repowered electric generation unit, a new process or production line, or other new gas-consuming equipment which is substantially stand-alone in nature) on or after March 1, 1998, and:

a. Is by itself of sufficient size to qualify for noncore service; and
b. Has separate PG&E metering, or other separate metering acceptable to PG&E.

3.2.1.2. The load must never have been physically connected to PG&E's local transmission or distribution system.

3.2.1.3. The lateral pipeline that delivers gas to the Customer's premise must be directly connected to PG&E's Backbone Transmission System, and must be either:

a. 100 percent owned by, or fully under the operational control of, the end-use Customer or its affiliate, provided that:
   i. The affiliate is wholly-owned and/or controlled by the Customer or a common parent of the Customer and the affiliate, and
   ii. The lateral is used exclusively by the Customer and/or its wholly-owned or commonly-controlled affiliates; or
b. Owned by PG&E, but paid for in advance by the end-use Customer pursuant to:
   i. An approved pro-forma agreement, such as Agreement to Perform Tariff Schedule Related Work (Form # 62-4527), Agreement for Installation or Allocation of Special Facilities (Form # 79-255), or Distribution and Service Extension Agreement, Cost Summary (Form # 79-1004), or
   ii. A negotiated agreement under the exceptional case provisions under PG&E's gas Rules 15 or 16, which is subsequently approved by the CPUC.

3.2.2. <u>Balancing Account for Changes to Customers Qualifying for Backbone Level End-Use Service</u>

PG&E will track the change in local transmission demand arising from any changes to the customers that are identified as being eligible for backbone level end-use service as of the date of a Commission order approving this Settlement. PG&E will record the revenue debit or credit entry based on the customer's actual annual demand multiplied by the applicable local transmission rate in effect, for each customer identified as a change. The tracked amount will be allocated to the Core Fixed Cost Account and the Noncore Customer Class Charge Account in the same proportion as local transmission costs are allocated between core and noncore customers, respectively, and will be reflected in rates in the Annual True-Up of Balancing Account filings (Annual True-Up). This treatment does not apply to new customers.

3.3. Local Transmission Service

Local transmission service remains the same. Except for customers qualifying for backbone level end-use service, this service continues to be non-bypassable for all on-system end-use and wholesale customers taking local transmission service from PG&E.

3.3.1. Bill Credit for Service to Moss Landing Units 1 and 2

A credit of $166,667 per month will be applied to the bill for local transmission service to Moss Landing Power Plant Units 1 and 2, effective with the implementation of the local transmission rates adopted for the Settlement Period. This $2 million per year will be collected through PG&E's backbone rates as a volumetric surcharge.

3.4. PG&E Authority to Negotiate Rate Discounts

Nothing in this Settlement alters PG&E's existing authority to negotiate rate discounts for backbone transmission service or for bundled end-use services. PG&E is willing to negotiate discounts to these services with customers that have competitive alternatives or under other circumstances that PG&E determines justify such discounts.

Also, nothing in this Settlement Agreement shall modify existing negotiated agreements between PG&E and any end-use customer or other shipper.

4. Storage Services

Storage services remain the same. Assignments of firm storage to PG&E's Core Procurement Department, pipeline balancing, and noncore storage service as approved in D.03-12-061 do not change during the Settlement Period, unless required by Commission order in R.04-01-025 or other regulatory proceeding. This includes the additional firm storage assigned to pipeline balancing in D.03-12-061.

4.1. Open Season

PG&E will not hold an open season for existing firm storage capacity at the beginning of the Settlement Period. Sufficient firm storage capacity remains available for any customer desiring this service.

4.2. Sale of Noncycle Working Gas

PG&E retains the right during the Settlement Period to file a Section 851 application to sell noncycle working gas in order to expand its annual ability to cycle storage on behalf of its storage customers.

4.3. Updated Report on Added Storage for Pipeline Balancing

When PG&E files its next rate case as provided in Section 2.2.1, PG&E will provide a full update to the "Report on Additional Storage Capacity for Pipeline Balancing Service" it filed on June 30, 2004, in A.04-03-021.

5. Cost of Service

5.1. Comparison to Filed Case

Appendix A, Table A-3 shows the adjustments from PG&E's filed cost of service, as updated in its June 11, 2004 Supplemental Filing. Appendix A, Table A-4 shows the cost of capital underlying this cost of service. As provided in Section 8.2, the cost of service and rates will be adjusted to reflect a Commission decision in PG&E's recently filed cost of capital case, A.04-05-023.

5.2. Allocation of Expenses

Under the Gas Accord, operating expenses were allocated to Unbundled Cost Categories (UCCs) primarily based on plant. Since then, more detailed data is available on operation and maintenance (O&M) expense incurrence by UCC. Consistent with other rate case approaches, this direct assignment method is to be used for allocating O&M expenses beginning January 1, 2006. For 2005, the allocation is based on half the O&M costs allocated using the direct assignment method and half using the plant method. Administrative and General (A&G) allocation to UCCs follows the O&M labor.

5.3. Revenue Requirement

The Gas Transmission and Storage revenue requirement over the Settlement Period is shown in the table below. The total revenue requirement escalates at two (2) percent for 2006 and 2007, except for the revenue requirement attributable to the G-XF contracts.

	2005	2006	2007
Backbone, without balancing	$210.3	$226.6	$231.2
G-XF Contracts	8.2	7.9	7.6
Local Transmission	146.1	135.9	138.6
Storage, including load balancing and non-base carrying costs	58.9	61.1	62.3
Net Revenue Requirement	$423.5	$431.5	$439.7
Customer Access Charge	5.0	5.1	5.2
Total Revenue Requirement	$428.5	$436.6	$444.9

6. Cost Allocation and Rates

Illustrative 2005 class average rates are shown in Appendix B, Tables 1 and 2. For noncore retail and wholesale customers, the rates reflect the impacts of the 2005 local transmission and customer access charges agreed to in this Settlement. For bundled core customers, the rates reflect the impacts of the 2005 local transmission, storage and intrastate backbone charges agreed to in this Settlement. For core transport customers, the rates reflect the impacts of the 2005 local transmission rates agreed to in this Settlement.

All rate changes will be effective January 1 of each year, including storage rates.

6.1. Backbone Load Factor, Cost Allocation and Rates

6.1.1. The backbone load factors used to determine firm backbone rates are:

2005	74.0 percent
2006	75.0 percent
2007	76.5 percent

These are negotiated numbers, and Settlement Parties do not take any position with respect to the underlying demand and throughput adjustments.

6.1.2. Core Vintage rate design for reserved Line 400 firm capacity is retained for the Settlement Period.

6.1.3. The backbone cost of service by UCC is allocated to paths based on firm capacities shown in Appendix A, Table A-5. This cost allocation methodology remains constant over the Settlement Period. The backbone cost allocation by path is shown in Appendix A, Table A-6.

6.1.4. Backbone rate design remains the same, except as set forth in Section 3.1.4, above. All path rates are based on the allocated costs and the backbone load factors specified in Section 6.1.1 above. G-XF rates continue to be calculated using incremental Line 401 costs.

6.1.5. Appendix B, Tables 3 through 9, show the backbone rates by service and rate design.

6.2. Storage Cost Allocation and Rates

Storage cost allocation and rate design methods remain the same. Appendix A, Tables A-7 and A-8 show the firm capacities used to allocate costs and the resulting cost allocation to Injection, Inventory and Withdrawal. Storage rates are shown in Appendix B, Table 10.

6.3. Local Transmission Throughput, Cost Allocation and Rates

6.3.1. The local transmission throughput is shown in Appendix A, Table A-9. The 2005 throughput increases at two (2) percent for 2006 and 2007 for purposes of calculating local transmission rates.

6.3.2. Local Transmission cost of service continues to be allocated to core and noncore customer classes based on Cold-Year January (CYJ) demand. This cost allocation is shown in Appendix A, Table A-10.

Local transmission rates continue to be designed on a postage stamp basis.

6.3.3. The core local transmission revenue requirement will receive full balancing account protection through monthly entries to the Core Fixed Cost Account (CFCA). This will reduce the year-to-year variability of this cost component.

6.3.4. Local Transmission rates are shown in Appendix B, Table 11.

6.4. Customer Access Charge

There are no changes to the current 2004 Customer Access Charges (CACs) rate structure. CACs applicable to industrial and electric generation customers are based on a six-tier fixed monthly charge rate design. The two-part fixed and volumetric Tier 6 CAC in PG&E's filed case has been eliminated. The CACs applicable to wholesale customers continue to be based on customer-specific CAC cost of service. These charges are shown in Appendix B, Table 12.

6.5. Self-Balancing Credit

If a customer elects to self-balance pursuant to Rate Schedule G-BAL, they receive a credit as shown in Appendix B, Table 13.

7. PG&E Core Procurement and Core Transportation Agents

7.1. Additional Core Storage Services

The Draft Decision of ALJ Fukutome and ALJ Wong, dated July 20, 2004, in Rulemaking 04-01-025 orders PG&E to file an application within six (6) months "to address how much, and by what process, incremental gas storage needs for the core should be put out to bid as well as other implementation issues that PG&E feels need to be address before the provisioning of core storage is opened to independent storage providers." PG&E's current Core Firm Storage assignment is outlined in Table A-7 of this settlement.

The Parties agree not to advocate modifications of the portion of the Draft Decision that would order incremental core storage service to be opened to independent storage providers. If this issue is not addressed in the Phase I decision expected to issue in R.04-01-025, PG&E agrees that within two months of Commission approval of this settlement, but not before February 2005, PG&E will file such an application addressing the same topics as specified in the Draft Decision. Regardless of whether this filing is made pursuant to this settlement or a Commission order in R.04-01-025, prior to filing the application, PG&E agrees to meet with ORA, TURN, third-party storage providers and other parties to discuss, and attempt to reach a consensus on the contents of such a filing regarding the manner in which a competitive bidding process for the incremental storage capacity needs of the core will be implemented.

7.2. GTN, TCBC and NGTL Capacity (Northern Interstate Path)

CTAs will have an annual option to accept a proportional share of firm capacity contracted for and held by PG&E for its core customers on Gas Transmission Northwest (GTN), TransCanada PipeLines B.C. System (TCBC, formerly ANG) and NOVA Gas Transmission Ltd. (NGTL, formerly NOVA) – the Northern Interstate Path. The amount of Northern Interstate Path capacity made available to the CTA will be the Group's January capacity factor times the firm interstate capacity reserved for PG&E's core customers. A CTA may elect to take all or part of their allocation provided the same percentage share is taken on all three pipelines. PG&E will provide this option annually on or before the 1st of September, and CTAs must respond with their election on or before September 30. Capacity will then be awarded for the one-year contract period starting November 1 each year.

Until CTA market share exceeds 5% of the core load, no adjustments will be made for an increase or decrease in aggregator load until the next annual assignment period. Once CTA market share exceeds 5% of core load, PG&E will propose an adjustment mechanism in the next available proceeding. CTAs may broker this assignment of capacity up to the end of the assignment period. New CTAs will wait until the next annual assignment period to receive a Northern Interstate Path assignment. All Northern Pipeline Path capacities that are not accepted for assignment by CTAs are assigned to PG&E's Core Procurement Group. Also, if a CTA terminates service and has not brokered its Northern Interstate Path assignment, the capacity will revert back to PG&E's Core Procurement Group.

This provision will be effective on November 1, 2005, and will extend through October 31, 2008. The current GTN and Firm Canadian Capacity provisions in schedule G-CT will be replaced. When and if the annual CTA load reaches 10% of the annual aggregate core load, all CTA pipeline allocations will be capped at 10% until the Commission reviews and approves a new process for future CTA pipeline allocations.

This section only applies to the Northern Interstate Path and not any other Core Procurement firm pipeline holdings.

7.3. Core Procurement Brokerage Fee

The Core Brokerage Fee is increased to $0.030 per Dth to reflect inflation since 1997. This change occurs as of the effective date of tariffs implementing this Settlement.

7.4. CTA Firm Winter Capacity Requirement

PG&E will modify the Firm Intrastate Pipeline Capacity Alternate Resource exemption provision in Schedule G-CT to exclude "High Inventory OFOs" when evaluating the exemption compliance provisions. Only Low Inventory OFOs would be counted when evaluating exemption compliance. Schedule G-CT would then read "*If a CTA has fulfilled this Firm Winter Capacity Requirement and has incurred no instances of non-compliance with an Emergency Flow Order*

(EFO) and no more than one (1) such instance with ~~and~~ ***Low Inventory*** *Operational Flow Order (OFO) as specified in Rule 14 for a two year period, the CTA will no longer be required to meet this Firm Winter Capacity Requirement."*

8. Rate Certainty and Adjustments During Term of Settlement

8.1. Rate Certainty

The rates specified in this Settlement Agreement are not subject to adjustment during the Settlement Period except as provided herein, or as agreed to by the Settlement Parties and approved by the Commission.

Nothing in this Settlement Agreement shall prevent PG&E from making adjustments to services, capacity assignments, cost allocations, rates or the like in order to comply with Commission orders in other proceedings. No Settlement Party shall make any proposal that would conflict with or alter any term of this Settlement Agreement, and the Settlement Parties shall not support proposals of others that would do the same.

8.2. Cost of Capital Adjustment

The cost of capital used to set rates for the Settlement Period will be the cost of capital for 2005 adopted by the Commission in A.04-05-023. Should this decision be delayed beyond January 1, 2005, the filed Settlement rates will apply for 2005, and the adjustment to 2005 revenues resulting from the cost of capital decision will be reflected in core and noncore customer rates in the next Annual True-Up filing consistent with the method approved in Advice 2521-G for recovery of Administrative and General expenses adopted in 2003 GRC D.04-05-055. For 2006 and 2007, rates will be adjusted prospectively for the effects of the 2005 cost of capital decision.

8.3. Line 57C Project

Rates may be adjusted during the Settlement Period to include the costs for the Line 57C Project, if approved by the Commission in a separate application, and if the project is placed in service during the Settlement Period.

8.4. Annual True-Up and BCAP Filings

Certain rates, such as the Distribution and Customer Class charge, will continue to change with PG&E's BCAP or Annual True-Up filings, and as a result of other Commission decisions. This Settlement Agreement does not change these existing procedures and filings.

8.5. Operational Provisions

During the term of the Settlement Agreement, operational issues may arise that need to be addressed. This Settlement Agreement does not preclude the ability of PG&E or any other party to bring operational issues and solutions to the Commission for its review and approval, or of any Settlement Party to respond as it deems appropriate should any operational issues and solutions be submitted to the Commission.

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APPENDIX A

Tables Supporting the Settlement

Gas Accord III Settlement Agreement

Appendix A

Table A-1
Backbone Capacity Assignments to Core Customers, MDth/d

Line No.		Summer	Fall/Spring	Winter
1	Redwood	608.766	608.766	608.766
2	Baja	155.000	310.000	669.000
3	Silverado	5.000	5.000	5.000
4	Total	768.766	923.766	1,282.766

Table A-2
Vintage Redwood Capacity Assignments to Core Retail and Core Wholesale Customers, MDth/d

Line No.	Customer	Vintage Redwood Assignment
1	Retail Core	608.766
2	Wholesale Core	
3	Alpine	0.098
4	Coalinga	0.552
5	Island Energy	0.064
6	Palo Alto	5.898
7	WCG – Castle	0.051
8	WCG – Mather	0.171
9	Subtotal Wholesale	6.834
10	Total	615.600

Table A-3
2005 Cost of Service Adjustments From Filed Case, $ Thousands

Line No.		
1	Filed 2005 COS	$433,887
2	A&G from GRC	(4,900)
3	Subtotal	$428,987
4	Adjustments:	
5	SMUD O&M Credit	(1,079)
6	SEGDA Credit	(823)
7	O&M / Capital Adjustment	(2,085)
8	Pipeline Balancing Adjustment	1,000
9	Adjusted 2005 COS	$426,000
10	Storage Carrying Costs (non-base revenue)	2,519
11	Revenue Requirement	$428,519

Table A-4
Cost of Capital Underlying Filed Cost of Service

	Share	Cost	Weighted
Debt	47.2%	6.70%	3.16%
Preferred Equity	2.3%	6.07%	0.14%
Common Equity	50.5%	11.22%	5.67%
Total	100.0%		8.97%

Table A-5
2005 Firm Capacity for Cost Allocation to UCC, MDth/d

Line No.	Rate Path	Line 400/ Line 2	Line 401	Redwood Expansion	Line 300	Gathering*	Other Backbone
1	On-System Backbone						
2	Redwood Vintage	615.6					615.6
3	Redwood	377.2	681.9	218.4	–	–	1,277.5
4	Baja	–	–		1,102.4	–	1,102.4
5	Silverado	–	–		–	155.4	155.4
6	Mission	–	–		–	–	–
7	Subtotal	992.8	681.9	218.4	1,102.4	155.4	3,150.9
8	G-XF Contracts		91.8		–	–	–
9	Total	992.8	773.7	218.4	1,102.4	155.4	3,150.9

* Calculated as 115 MDth per day divided by the backbone load factor.

Table A-6
Costs by Backbone Path* for 2005, 2006 and 2007, $ Million

Line No.	Backbone Path*	2005	2006	2007
1	Redwood Path – Core	$ 26.3	$ 29.1	$ 29.7
2	Redwood Path	105.1	108.6	110.8
3	Line 401 Incremental G-XF	8.2	7.9	7.5
4	Subtotal Redwood	$139.6	$145.6	$148.0
5	Baja	81.6	91.6	93.5
6	Silverado	7.3	7.7	7.8
7	Total	$228.5	$244.9	$249.3

* Includes Storage Load Balancing from Table A-8.

Table A-7
Firm Capacity for Storage Cost Allocation to Services

Line No.	Storage Service	Annual Average Injection MDth/d	Inventory MMDth	Annual Average Withdrawal MDth/d
1	Firm Storage Services			
2	Core Firm Storage	112.533	33.478	489.318
3	Standard Firm Storage	16.524	4.783	93.932
4	Monthly Balancing Service	76.125	4.100	76.125
5	Total	205.181	42.360	659.375

Table A-8
Storage Cost Allocation to Services for 2005, 2006 and 2007, $ Million

Line No.	Storage Service	2005	2006	2007
1	Firm Storage Services			
2	Core Firm Storage	$41.6	$43.1	$44.0
3	Standard Firm Storage	7.3	7.6	7.8
4	Monthly Balancing Service*	10.0	10.3	10.6
5	Total	$58.9	$61.0	$62.3

* Included in Backbone Transmission Costs in Table A-6.

Table A-9
Local Transmission Throughput For 2005, 2006 and 2007, MDth/d

Line No.		
1	Core	820.9
2	Noncore Non-EG	415.3
3	Electric Generation and Cogeneration	628.8
4	Wholesale	10.5
5	Total End-Use	1,875.5
6	Backbone End-Use	(185.7)
7	G-10 and EAD Discount Adjustments	(58.5)
8	2005 LT Throughput	1,631.3
9	2006 LT Throughput (2% growth)	1,664.0
10	2007 LT Throughput (2% growth)	1,697.2

Table A-10
Local Transmission Cost Allocation To Customer Classes
for 2005, 2006 and 2007

Line No.	Local Transmission	2005	2006	2007
1	Core CYJ Demand, Mth	570,184	570,184	570,184
2	Percentage	70.03%	70.03%	70.03%
3	Noncore CYJ Demand on LT, Mth	243,982	243,982	243,982
4	Percentage	29.97%	29.97%	29.97%
5	Total CYJ on LT, Mth	814,166	814,166	814,166
6	Core, $ Million	$102.3	$ 95.2	$ 97.1
7	Noncore, $ Million	43.8	40.7	41.5
8	Total, $ Million	$146.1	$135.9	$138.6

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APPENDIX B

Detailed Rate Tables

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Appendix B

Table 1
Illustrative End-Use Class Average Rates ($/dth

	Present Rates 2004	Settlement Rates 2005	% Change
Core Retail Bundled Service (b)			
Residential	9.099	9.141	0.5%
Small Commercial	8.524	8.564	0.5%
Large Commercial	7.273	7.301	0.4%
Core Average	8.957	8.998	0.5%
Core Retail Transport-Only (c)			
Residential	3.617	3.586	-0.9%
Small Commercial	3.070	3.039	-1.0%
Large Commercial	2.042	2.011	-1.5%
Core Transport Average	3.434	3.396	-1.1%
Wholesale Transportation-Only (c)			
Alpine Natural Gas	0.326	0.260	-20.5%
Coalinga	0.330	0.252	-23.8%
Island Energy	0.596	0.451	-24.4%
Palo Alto	0.219	0.187	-14.8%
West Coast Gas - Castle	0.615	0.462	-24.8%
West Coast Gas - Mather	0.407	0.260	-36.1%
Wholesale Transportation Average	0.239	0.201	-16.0%
Noncore Retail Transportation-Only (c)			
Industrial - Distribution	1.121	1.112	-0.9%
Industrial - Transmission	0.476	0.416	-12.6%
Industrial - Backbone	0.476	0.237	-50.2%
Electric Generation - Distribution/Transmission	0.205	0.193	-5.8%
Electric Generation - Backbone	0.205	0.045	-78.1%
Noncore Transportation Average	0.367	0.303	-17.2%

Notes:

a) Present 2004 rates are based on PG&E's 1999 General Rate Case (GRC) Decision 00-02-046, the Gas Accord Decision 03-12-061, the 2000 BCAP Decision 01-11-001 and 2004 True-Up Filings (Advice 2498-G, 2508-G, and 2514B-G) for the period beginning April 1, 2004. For consistency in rates comparison purposes, present rates and other rate components not addressed in this case, have been held consistent with the rates filed in the March 19, 2004 Application.

b) PG&E's bundled gas service is for core customers only. Intrastate backbone transmission and storage costs addressed in this proceeding, are included in end use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, and core brokerage. An illustrativ weighted average cost of gas (WACOG) of $4.44 is assumed in all present and proposed bundled core rates. Core bundled rates also includes the cost of transportation and delivery of gas from the citygate to the customer's burnertip, including local transmission, distribution, customer access, public purpose, and customer class charges.

c) PG&E's transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's citygate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission, including distribution, customer access, public purpose programs and customer class charges. Transportation-only rates exclude backbone transmission and storage costs.

d) Actual transportation rates will vary depending on the customer's load factor and seasonal usage. The rates shown here ar averages for each class.

e) Dollar difference are due to rounding.

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Table 2
2005 Rate Detail By End-Use Customer Class, Including Illustrative Components
($/dth)

	Core (a)			Noncore Transportation				
				Industrial			Electric Gen	
	Res	Small Comm	Large Comm	Dist	Trans	BB	D/T	BB
Transportation Charges:								
Local Transmission	0.342	0.342	0.342	0.148	0.148	0.000	0.148	0.000
Customer/ Customer Access Charge (b)	0.000	0.358	0.070	0.082	0.021	0.021	0.009	0.009
Gas Public Purpose Program Surcharge	0.302	0.266	0.669	0.192	0.180	0.180	0.000	0.000
CPUC FEE	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007
Customer Class Charge	0.077	0.079	0.083	(0.004)	0.028	0.028	0.022	0.022
Distribution (c)	2.858	1.986	0.840	0.686	0.031	0.000	0.006	0.006
Total Transportation Rate	3.586	3.039	2.011	1.112	0.416	0.237	0.193	0.045

	Res	Small Comm	Large Comm
Procurement Charges for Core Bundled Customers:			
Storage	0.139	0.132	0.096
Backbone Capacity	0.163	0.157	0.105
Backbone Usage	0.061	0.061	0.061
WACOG (d)	4.436	4.436	4.436
Interstate Capacity and Other	0.755	0.738	0.591
Total Core Procurement	5.555	5.525	5.289
Total Core Bundled Rates	9.141	8.564	7.301

Wholesale Transportation

Transportation Charges:	Alpine	Coalinga	Island Energy	Palo Alto	WCG Castle	WCG Mather
Local Transmission	0.148	0.148	0.148	0.148	0.148	0.148
Customer/ Customer Access Charge (b)	0.089	0.082	0.280	0.017	0.292	0.090
Gas Public Purpose Program Surcharge	0.000	0.000	0.000	0.000	0.000	0.000
Customer Class Charge	0.022	0.022	0.022	0.022	0.022	0.022
Total Transportation Rate	0.260	0.252	0.451	0.187	0.462	0.260

Notes:

a) Class average rates reflect load shape for bundled core.

b) Customer access and customer charges represent the class average volumetric equivalent of the monthly charge.

c) Distribution rates represent the annual class average.

d) Reflects the $4.44/dth WACOG, adjusted for intrastate backbone usage charges.

e) Dollar difference are due to rounding.

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Table 3
Firm Backbone Transportation
<u>Annual Rates (AFT) -- SFV Rate Design</u>
On-System Transportation Service

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
<u>Redwood - Core</u>						
Reservation Charge	($/dth/mo)	3.846	5.189	4.474	4.905	4.906
Usage Charge	($/dth)	0.002	0.012	0.014	0.014	0.014
Total	($/dth @ Full Contract)	0.129	0.182	0.161	0.176	0.176
<u>Redwood Path</u>						
Reservation Charge	($/dth/mo)	9.060	9.725	9.171	9.349	9.355
Usage Charge	($/dth)	0.002	0.005	0.008	0.008	0.008
Total	($/dth @ Full Contract)	0.300	0.325	0.309	0.315	0.315
<u>Baja Path</u>						
Reservation Charge	($/dth/mo)	5.722	9.459	8.010	8.917	8.923
Usage Charge	($/dth)	0.004	0.013	0.015	0.015	0.015
Total	($/dth @ Full Contract)	0.192	0.324	0.279	0.309	0.309
<u>Silverado and Mission Paths</u>						
Reservation Charge	($/dth/mo)	3.452	5.053	4.412	4.629	4.632
Usage Charge	($/dth)	0.001	0.004	0.007	0.007	0.007
Total	($/dth @ Full Contract)	0.115	0.170	0.152	0.159	0.159

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 74, 75, 76.5 percent load factor for 2005, 2006, and 2007 respectively.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Dollar difference are due to rounding.

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Table 4
Firm Backbone Transportation
<u>Annual Rates (AFT) -- MFV Rate Design</u>
On-System Transportation Service

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Redwood - Core						
Reservation Charge	($/dth/mo)	2.962	4.049	3.378	3.802	3.803
Usage Charge	($/dth)	0.031	0.049	0.050	0.051	0.051
Total	($/dth @ Full Contract)	0.129	0.182	0.161	0.176	0.176
Redwood Path						
Reservation Charge	($/dth/mo)	5.357	5.822	5.406	5.559	5.562
Usage Charge	($/dth)	0.124	0.133	0.132	0.132	0.133
Total	($/dth @ Full Contract)	0.300	0.325	0.309	0.315	0.315
Baja Path						
Reservation Charge	($/dth/mo)	4.468	7.317	5.941	6.834	6.838
Usage Charge	($/dth)	0.045	0.083	0.083	0.084	0.084
Total	($/dth @ Full Contract)	0.192	0.324	0.279	0.309	0.309
Silverado and Mission Paths						
Reservation Charge	($/dth/mo)	2.498	3.550	3.024	3.232	3.234
Usage Charge	($/dth)	0.033	0.053	0.052	0.053	0.053
Total	($/dth @ Full Contract)	0.115	0.170	0.152	0.159	0.159

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 74, 75, 76.5 percent load factor for 2005, 2006, and 2007 respectively.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Dollar difference are due to rounding.

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Table 5
Firm Backbone Transportation
<u>Seasonal Rates (SFT) -- SFV Rate Design</u>
On-System Transportation Service

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
<u>Redwood Path</u>						
Reservation Charge	($/dth/mo)	10.871	11.670	11.004	11.219	11.225
Usage Charge	($/dth)	0.002	0.006	0.009	0.009	0.009
Total	($/dth @ Full Contract)	0.360	0.390	0.371	0.378	0.378
<u>Baja Path</u>						
Reservation Charge	($/dth/mo)	6.866	11.351	9.612	10.701	10.707
Usage Charge	($/dth)	0.004	0.015	0.018	0.019	0.019
Total	($/dth @ Full Contract)	0.230	0.389	0.334	0.370	0.371
<u>Silverado Path</u>						
Reservation Charge	($/dth/mo)	4.142	6.063	5.294	5.555	5.559
Usage Charge	($/dth)	0.002	0.005	0.008	0.008	0.008
Total	($/dth @ Full Contract)	0.138	0.204	0.182	0.191	0.191

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Dollar difference are due to rounding.

Table 6
Firm Backbone Transportation
Seasonal Rates (SFT) -- MFV Rate Design
On-System Transportation Service

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Redwood Path						
Reservation Charge	($/dth/mo)	6.428	6.987	6.486	6.671	6.675
Usage Charge	($/dth)	0.148	0.160	0.158	0.159	0.159
Total	($/dth @ Full Contract)	0.360	0.390	0.371	0.378	0.378
Baja Path						
Reservation Charge	($/dth/mo)	5.361	8.780	7.129	8.201	8.206
Usage Charge	($/dth)	0.054	0.100	0.100	0.101	0.101
Total	($/dth @ Full Contract)	0.230	0.389	0.334	0.370	0.371
Silverado Path						
Reservation Charge	($/dth/mo)	2.997	4.260	3.629	3.878	3.881
Usage Charge	($/dth)	0.039	0.064	0.063	0.063	0.063
Total	($/dth @ Full Contract)	0.138	0.204	0.182	0.191	0.191

Notes:

a) Firm Seasonal rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Customers delivering gas to storage pay the applicable backbone transmission on-system rate from Redwood, Baja and Silverado.

e) Firm seasonal service is available to on-system paths for a minimum term of three consecutive months in one season. Winter season is November through March. Summer season is April through October.

f) Dollar difference are due to rounding.

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Table 7
As-Available Backbone Transportation
On-System Transportation Service (AA)

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Redwood Path						
Usage Charge	($/dth)	0.360	0.390	0.371	0.378	0.378
Baja Path						
Usage Charge	($/dth)	0.230	0.389	0.334	0.370	0.371
Silverado Path						
Usage Charge	($/dth)	0.138	0.204	0.182	0.191	0.191
Mission Path						
Usage Charge	($/dth)	0.000	0.000	0.000	0.000	0.000

Notes:

a) As-Available rates are 120 percent of Firm Annual rates.

b) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

c) Mission path service represents on-system storage to on-system transportation. Customers delivering gas to storage facilities pay the applicable backbone transmission on-system rate from Redwood, Baja or Silverado.

d) Dollar difference are due to rounding.

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Table 8
Backbone Transportation
Annual Rates (AFT-Off)
Off-System Deliveries

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
SFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	9.060	9.725	9.171	9.349	9.355
Usage Charge	($/dth)	0.002	0.005	0.008	0.008	0.008
Total	($/dth @ Full Contract)	0.300	0.325	0.309	0.315	0.315
Baja Path Off-System						
Reservation Charge	($/dth/mo)	5.722	9.459	8.010	8.917	8.923
Usage Charge	($/dth)	0.004	0.013	0.015	0.015	0.015
Total	($/dth @ Full Contract)	0.192	0.324	0.279	0.309	0.309
MFV Rate Design						
Redwood, Silverado and Mission Paths Off-System						
Reservation Charge	($/dth/mo)	5.357	5.822	5.406	5.559	5.562
Usage Charge	($/dth)	0.124	0.133	0.132	0.132	0.133
Total	($/dth @ Full Contract)	0.300	0.325	0.309	0.315	0.315
Baja Path Off-System						
Reservation Charge	($/dth/mo)	4.468	7.317	5.941	6.834	6.838
Usage Charge	($/dth)	0.045	0.083	0.083	0.084	0.084
Total	($/dth @ Full Contract)	0.192	0.324	0.279	0.309	0.309
As-Available Service						
Redwood, Silverado, and Mission Paths, (From Citygate) Off-System						
Usage Charge	($/dth)	0.360	0.390	0.371	0.378	0.378
Mission Paths (From on-system storage) Off-System						
Usage Charge	($/dth)	0.360	0.390	0.000	0.000	0.000
Baja Path Off-System						
Usage Charge	($/dth)	0.230	0.389	0.334	0.370	0.371

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) Backbone transmission charges are based on a 74, 75, 76.5 percent load factor for 2005, 2006, and 2007 respectively.

c) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

d) Except for as-available service from on-system storage to off-system, California gas and storage to off-system are assumed to flow on Redwood path and are priced at the Redwood path rate.

e) Dollar difference are due to rounding.

Table 9
Firm Transportation
Expansion Shippers -- Annual Rates (G-XF)
SFV Rate Design
Off-System Deliveries

SFV Rate Design		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Reservation Charge	($/dth/mo)	7.900	7.461	7.414	7.136	6.846
Usage Charge	($/dth)	0.001	0.001	0.001	0.001	0.001
Total	($/dth @ Full Contract)	0.261	0.246	0.245	0.236	0.226

Notes:

a) Rates are only the backbone transmission charge component of the transmission service. They exclude local transmission charges, customer class charges, customer access charges, distribution charges, storage charges, and shrinkage charges.

b) The "Total" rows represent the average backbone transmission charge incurred by a firm shipper that uses its full contract quantity at a 100 percent load factor.

c) G-XF charges are based on the embedded cost of Line 401 and a 95 percent load factor.

d) Dollar difference are due to rounding.

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Table 10
Storage Services

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Core Firm Storage (G-CFS)						
Reservation Charge	($/dth/mo)	0.096	0.107	0.104	0.107	0.109
Standard Firm Storage (G-SFS)						
Reservation Charge	($/dth/mo)	0.118	0.132	0.128	0.133	0.135
Negotiated Firm Storage (G-NFS)						
Injection	($/dth/d)	13.707	15.266	14.826	15.365	15.672
Inventory	($/dth/mo)	1.421	1.582	1.537	1.593	1.624
Withdrawal	($/dth/d)	10.334	11.509	11.178	11.584	11.815
Negotiated As-Available Storage (G-NAS) - Maximum Rate						
Injection	($/dth/d)	13.707	15.266	14.826	15.365	15.672
Withdrawal	($/dth/d)	10.334	11.509	11.178	11.584	11.815
Market Center Services (Parking and Lending Services)						
Maximum Daily Charge ($/Dth/day)		0.820	0.946	0.921	0.953	0.972
Minimum Rate (per transaction)		$ 57.00	$ 57.00	$ 57.00	$ 57.00	$ 57.00

Notes:

a) Rates for storage services are based on the costs of storage injection, inventory and withdrawal.

b) Core Firm Storage (G-CFS) and Standard Firm Storage (G-SFS) rates are a monthly reservation charge designed to recover one twelfth of the annual revenue requirement of injection, inventory and withdrawal storage.

c) Negotiated Firm rates may be one-part rates (volumetric) or two-part rates (reservation and volumetric), as negotiated between parties. The volumetric equivalent is shown above.

d) Negotiated As-Available Storage Injection and Withdrawal rates are recovered through a volumetric charge only.

e) Negotiated rates (NFS and NAS) are capped at the price which will collect 100 percent of PG&E's total revenue requirement for the unbundled storage program under all three subfunctions (e.g. inventory, injection, or withdrawal). The maximum rates are based on a rate design assuming an average injection period of 30 days and an average withdrawal period of 7 days.

f) Negotiated Firm and As-available services are negotiable above a price floor representing PG&E's marginal costs of providing the service.

g) The maximum charge for parking and lending is based on the annual cost of cycling one dth of Firm Storage Gas assuming the full 214 day injection season and 151 day withdrawal season.

h) Gas Storage shrinkage will be applied in-kind on storage injections.

i) Dollar difference are due to rounding.

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Table 11
Local Transmission Rates
($/dth)

	GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Core Retail	0.367	0.317	0.342	0.312	0.312
Noncore Retail and Wholesale	0.157	0.137	0.148	0.135	0.135

Notes:
a) Dollar difference are due to rounding.

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Table 12
Customer Access Charges

		GA II 2004	July 14, 2004 Testimony	2005	2006	2007
G-EG / G-NT ($/month)						
Transmission and Distribution	(Therms/Month)					
Tier 1	0 to 5,000	$30.12	$ 65.05	$ 62.72	$ 64.24	$ 65.52
Tier 2	5,001 to 10,000	$237.27	$ 192.34	$ 185.46	$ 189.93	$ 193.73
Tier 3	10,001 to 50,000	$900.15	$ 354.60	$ 341.91	$ 350.15	$ 357.16
Tier 4	50,001 to 200,000	$2,372.80	$ 464.85	$ 448.21	$ 459.02	$ 468.20
Tier 5	200,001 to 1,000,000	$3,397.26	$ 671.72	$ 647.68	$ 663.30	$ 676.56
Tier 6	1,000,001 and above	$9,875.46	$ 2,516.48	$5,450.83	$ 5,582.25	$5,693.90
Tier 6	Usage Charge $/dth	$ -	$ 0.006	$ -	$ -	$ -
Wholesale ($/month)						
Alpine		$524.45	$ 331.56	$ 319.69	$ 327.40	$ 333.95
Coalinga		$2,608.37	$ 1,466.42	$1,413.93	$ 1,448.02	$1,476.98
Island Energy		$1,421.98	$ 993.56	$ 957.99	$ 981.09	$1,000.71
Palo Alto		$11,144.58	$ 4,889.36	$4,714.35	$ 4,828.01	$4,924.57
West Coast Gas - Castle		$1,223.40	$ 851.84	$ 821.35	$ 841.15	$ 857.97
West Coast Gas - Mather		$1,894.90	$ 778.46	$ 750.59	$ 768.69	$ 784.06

Notes:
a) Dollar difference are due to rounding.

Table 13
Self Balancing Credit
$/dth

	GA II 2004	July 14, 2004 Testimony	2005	2006	2007
Self Balancing Credit	(0.010)	(0.011)	(0.010)	(0.011)	(0.011)

Notes:

a) Storage balancing costs are bundled in backbone rates. Customers or Balancing agents who elect self balancing on a daily basis can opt out of PG&E's monthly balancing program and receive a self-balancing credit.

b) Dollar difference are due to rounding.