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Commissioner:	
Admin. Law Judge:	Karen V. Clopton

DIVISION OF RATEPAYER ADVOCATES
California Public Utilities Commission

MONITORING AND EVALUATION REPORT

November 1, 2008 through October 31, 2010

Pacific Gas and Electric Company's
Core Procurement Incentive Mechanism
Performance Results
(CPIM Year 16 and 17)

Application 96-08-043

San Francisco, California
April 30, 2012

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CHAPTER 1
SUMMARY AND RECOMMENDATIONS

1.1 Introduction and Summary

The Division of Ratepayer Advocates (DRA) performed an audit and evaluation of the data and documents submitted by Pacific Gas and Electric Company (PG&E) for its Core Procurement Incentive Mechanism (CPIM) Annual Performance Reports for the period November 1, 2008 through October 31, 2009 (Year 16) and the period November 1, 2009 through October 31, 2010 (Year 17). The details and results of DRA's review are presented in Chapter 2 and 3 of this DRA CPIM Monitoring and Evaluation (M&E) Report. DRA's evaluation of PG&E's recorded natural gas costs confirms that PG&E's costs were below the benchmark for periods Year 16 and 17 which resulted in savings for ratepayers.

For Year 16, PG&E submitted its CPIM Performance Report on March 5, 2010 for the period November 1, 2008 through October 31, 2009. DRA's examination of PG&E's recorded costs for Year 16 shows that PG&E's costs were below the benchmark lower tolerance band, which results in a reward of $4,623,381 to PG&E's shareholders and a ratepayer benefit of $23,116,901.

For Year 17, PG&E submitted its CPIM Performance Report on March 16, 2011 for the period November 1, 2009 through October 31, 2010. DRA's examination of PG&E's recorded costs for Year 17 shows that PG&E's costs were below the benchmark lower tolerance band, which results in a reward of $4,295,235 to PG&E's shareholders and a ratepayer benefit of $21,476,184.

1.2 Background

The objective of the CPIM is to provide PG&E an incentive to reduce natural gas procurement costs. These costs include fixed transportation costs for Canadian, interstate, intrastate, and reservation costs. Other procurement costs include pipeline, volumetric transportation costs, and natural gas storage. The incentive mechanism is used as a ratemaking tool that is designed to increase efficiency in administering regulatory controls.

The CPIM structure establishes procedures on performance evaluation and reporting for PG&E's gas procurement costs. It sets forth guidelines for standard operating conditions and for special circumstances. The allowed monthly benchmark dollars are totaled over the annual CPIM period and compared to actual costs for the year to determine PG&E's performance. A tolerance band is constructed around the benchmark, and is defined as a range of costs that is considered reasonable. If PG&E's actual gas costs, as measured against the CPIM benchmark are between the upper and lower limit specifications for the tolerance band, there is no shareholder reward or penalty for the CPIM period. If actual costs fall outside the tolerance band, there will be sharing between ratepayers and PG&E shareholders of the gains or losses that occur outside the tolerance band. Detailed results of the tolerance band calculation are reported in Chapter 2 and 3 of this report.

The CPIM program was originally approved by the Commission in D.97-08-055 as set forth in the PG&E/DRA Post-1997 CPIM Agreement and PG&E's Supplemental Report describing the Post-1997 CPIM. It established the framework to recover core gas procurement and transportation costs through rates. Since then, numerous changes and extensions have modified and refined the CPIM program structure and incentives.

In D.07-06-013, the Commission approved a settlement agreement between PG&E, DRA, The Utility Reform Network (TURN), and Aglet Consumer Alliance (Aglet). The settlement modified the CPIM to increase benefits to ratepayers in situations where natural gas purchases are less than the lower range of the tolerance band. The specific CPIM changes included are as follows:

- A 20/80 shareholder/ratepayer sharing of savings below the tolerance band, in contrast to the previous 25/75 shareholder/ratepayer sharing;
- The 2.5 Bcf un-sequenced storage withdrawal adjustment is eliminated and is to be included proportionately to the storage withdrawal sequence;
- Sequencing steps for San Juan Basin and AECO to change for natural gas purchases;
- Savings of five-percent (5%) from full tariff rates on pipeline or storage contracts are to offset CPIM gas costs;

- The index used to calculate the benchmark for daily swing purchases will change from the NGI daily Topock index to using the NGI daily PG&E CityGate index;
- For storage acquired via the Incremental Storage Capacity Request for Offers process, the daily benchmark will be adjusted to accommodate the incremental storage injection and withdrawal requirements to improve savings in gas costs.

In D.10-01-023, the Commission adopted a settlement agreement between PG&E, DRA, and TURN which addressed the treatment of hedging costs for PG&E. The key provisions of the adopted settlement call for the following treatment of hedging transactions:

- 80% of net realized gains or losses and associated transaction costs will be included in the CPIM Benchmark.
- 100% of the net hedging realized gains or losses and associated transaction costs will be included in the cost side of the CPIM calculation. Any gains will be subtracted and losses will be added to CPIM costs.
- The CPIM sharing mechanism is modified such that total shareholders earnings will be capped solely at 1.5 percent of annual gas commodity costs. The hard dollar cap of $25 million on shareholder gains is removed effective November 1, 2009.

1.3 Procurement and Sales

PG&E’s actual gas purchase costs (including commodity, transportation, and storage) for Year 16 totaled $1,213,790,801 for a volume of 268,533,760 MMBtus (net of sales). For Year 17, PG&E's actual gas purchase costs totaled $1,447,109,402 for a volume of 279,863,168 MMBtus (net of sales).

The cost component of the benchmark includes fixed transportation and reservation costs which relate to capacity holdings for the following pipeline systems: a) TransCanada Pipelines Limited - NOVA, Foothills, and Gas Transmission Northwest; b) El Paso Natural Gas (EPNG); c) Transwestern Pipeline Company (TW); and d) PG&E's California Gas Transmission (CGT). The costs of interstate, intrastate and storage capacity accepted by Core Transport Agents (CTAs) for services provided through core aggregation are not included in the CPIM benchmark or actual costs. These costs are recovered directly from CTAs, per D.97-12-032 and PG&E's Schedule G-CT - Core Gas Aggregation Service.[1]

In addition, the variable cost component of the benchmark represents the cost of gas, which includes fuel and volumetric transportation charges delivered to PG&E's Citygate, where PG&E's backbone transmission system connects to the local distribution system.

PG&E manages gas sales to meet the following requirements:

a) Offset gas costs;

b) Comply with daily pipeline balancing requirements;

c) To respond to changing core loads.

For Year 16, PG&E reported total gas sales of $303,281,181 for 71,993,435 MMBtus. Year 16 sales were comprised of seventy-eight percent (78%) at the CityGate, Canadian sales were eighteen percent (18%), Transwestern sales were two percent (2%), and EPNG was two percent (2%). For Year 17, total sales were $264,522,539 for 57,195,599 MMBtus. Year 17 sales were comprised of sixty-nine percent (69%) at the CityGate, Canadian sales were eighteen percent (18%), Transwestern sales were three percent (3%), and EPNG was ten percent (10%). As part of gas sales, PG&E reported gas by-product extraction revenues of $7,322,623 for Year 16 and $12,316,451 for Year 17.

1.4 Financial Hedging Activities

For Years 16 and 17, all derivative gains, losses and related transaction costs associated with PG&E's winter hedge plan are not included in CPIM costs per D.07-06-013. These costs flow directly to PG&E's retail customers. D.07-06-013 authorizes PG&E under the settlement to place financial hedges on a rolling three-year basis via an Annual Plan filing. PG&E was required to file five Annual Plans beginning with the 2007/2008 winter season that will authorize a hedge plan for the current winter season

[1] PG&E's Annual CPIM Performance Report, dated March 5, 2010.

and the subsequent two winter seasons. In addition, the settlement creates a Core Hedging Advisory Group where DRA, Aglet, TURN and PG&E are to meet quarterly to discuss PG&E's Annual Plan, and related hedging operations.

By April 1 of each year, PG&E is required to report financial results of its Annual Plan which includes total funds spent on hedging instruments, total losses and gains for each category of hedging instrument, amount of monthly natural gas supplies hedged, and the impact of hedging results on customer rates.[2]

Pursuant to D.10-01-023, PG&E remains responsible to manage hedges proactively to ensure stability in customer rates. This includes implementing controls and selecting appropriate hedging instruments to mitigate derivative risks. PG&E is also required to take proactive steps by adjusting its hedging positions in response to changing market conditions.

The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 16 were $91,214,310. These costs were comprised of $52,023,623 in option premium costs and $39,190,687 in financial swap losses. The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 17 were $86,340,406. These costs were comprised of $23,761,116 in option premium costs and $62,579,290 in financial swap losses. DRA's financial hedging analysis is found in Sections 2.9 and 3.9 of this report.

Midway through Year 17, the Commission approved D.10-01-023 and associated Settlement Agreement which requires eighty percent (80%) of winter hedging gains and losses and related transaction costs to be included in the CPIM benchmark. Also, one hundred percent (100%) of winter hedging gains and losses and related transaction costs will be included in the CPIM actual commodity costs. Hedging gains are to be subtracted, and hedging losses are to be added to CPIM costs. These CPIM changes will be incorporated starting in CPIM Year 18.

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[2] Settlement Agreement – Regarding PG&E Long-Term Core Hedge Program (A.06-05-007), the Core Procurement Incentive Mechanism (CPIM), and Transportation Capacity held on Behalf of Core Customers, December 15, 2006.

1.5 Natural Gas Storage

Under the CPIM, PG&E has a daily injection and withdrawal schedule. During CPIM Year 16, storage inventory injections were 2,740,237 MMBtus, and storage withdrawals were 2,188,412 MMBtus. Beginning inventory was reported at 31,674,687 MMBtus, and ending inventory shows 33,226,512 MMBtus which is consistent with the required inventory of 33.5 MMdth.

For CPIM Year 17, storage inventory injections were 1,331,904 MMBtus, and storage withdrawals were 1,549,290 MMBtus. Beginning inventory was reported at 31,122,862 MMBtus, and ending inventory shows 31,905,476 MMBtus, which also complies with the required inventory of 33.5 MMdth.

Pursuant to D.06-017-010 and D.07-06-013, PG&E is authorized to acquire incremental storage to meet a 1-day-in-10-year peak-planning standard for its core customers. In 2007, PG&E executed two incremental storage contracts providing for 100,000 Dth per day of additional withdrawal capability for Year 16 winter season (2008-2009). PG&E subsequently executed additional storage contracts that cover Years 16, 17, and 18. For Year 16, incremental storage was 36,072,500 MMBtus.

In Year 17, incremental storage was reported at 39,349,660 MMBtus where costs are included in the benchmark and inventory schedules are adjusted by the amount of daily injections and withdrawals on a daily basis. This enables PG&E to track costs for the benchmark and adjust the amount of daily actual incremental natural gas injection and withdrawals.

Pursuant to Commission Decision 06-07-010, and modified by D.08-07-009, PG&E acquired additional incremental storage capacity for future winter season periods for 2011 through 2015. This capacity will become effective in Year 18 for the sole purpose of injection activity.

On August 7, 2009, the Commission approved Advice Letter 3031-G which authorizes PG&E to acquire additional incremental storage capacity to improve its reliability during peak demand periods. These acquisition costs will be reported in CPIM Years 18 through 22.

A change of firm storage injection and withdrawal requirements used to calculate the CPIM benchmark was agreed to with a Memorandum of Understanding

(MOU) between PG&E and DRA on October 19, 2009. These changes provide an updated profile of storage beginning in Year 17 when core storage will be adjusted for Core Transport Agents (CTAs) as stated in Tariff G-CT. This MOU will remain in effect until both parties agree to make changes.[3]

1.6 Core Intrastate Capacity

Pursuant to Commission D.04-12-050 (Gas Accord III) (A.04-03-021), PG&E is authorized to hold and recover costs for firm reservations of intrastate backbone pipeline capacity.

Pursuant to D.07-07-002, dated July 12, 2007, PG&E's Baja Path quantities were changed which resulted in annual capacity allocated to PG&E's core to 348 MDth per day and winter seasonal (December through February) at 321 Mdth per day. Therefore, the combined annual and winter Baja core capacity holdings are 669 MDth per day.

During Year 17, the Commission approved the Gas Accord V Settlement (effective CPIM Year 18), allows PG&E to retain existing quantities at the Baja Path but eliminate Silverado capacity.

1.7 Core Interstate Capacity

PG&E holds interstate capacity for the core on Trans-Canada NOVA (NGTL), Trans-Canada BC System, Trans-Canada Gas Transmission Northwest (GTN), El Paso Natural Gas Company (EPNG), and Transwestern Pipeline Company (TW). During Year 16, PG&E's core interstate capacity holdings were approximately 619 MDth/d on NOVA, 611 MDth/d on the BC System, 610 MDth/d on GTN, 267 MDth/d on EPNG, and 205 MDth/d on TW.[4]

For Year 17, core interstate capacity was reported at approximately 619 MDth/d for NOVA, 611 MDth/d on the BC System, 610 MDth/d on GTN, 202 MDth/d on EPNG, and 297 MDth/d on TW.[5]

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[3] CPIM - DRA and PG&E Memorandum of Understanding, dated October 19, 2009.

[4] PG&E Annual Performance Report, Year 16, Table III.

[5] PG&E Annual Performance Report, Year 17, Table III.

Pursuant to D.04-09-022, the Commission authorized PG&E to seek pre-approval and expedited advice letter treatment for interstate capacity contracts that meet specified criteria. Prior to seeking pre-approval, PG&E is required to consult with DRA, TURN and the Energy Division (ED) to obtain agreement from DRA.

During Year 16, there were no changes to the annual core capacity holdings on Transwestern, and Canadian capacity. However, PG&E submitted an expedited Advice Letter 3064-G to request approval to renew El Paso contracts. PG&E acquired peak winter pipeline capacity on El Paso for the three month winter period of December 2008 through February 2009.

During Year 17, there were changes to the annual core capacity holdings of Transwestern, and Canadian capacity. Pursuant to expedited Advice Letter 3100-G, approved on March 23, 2010, PG&E was authorized to extend its Transwestern contract for an additional two years. In addition, PG&E acquired peak winter pipeline capacity from Transwestern for the three month winter period of December 2009 through February 2010.

Pursuant to Advice Letter 3153-G, approved on October 21, 2010, the Commission authorized PG&E to extend two of its three existing contracts with NGTL. The Advice Letter also approved a one year contract extension for two contracts from Foothills (Canadian System). Table 2-14 for Year 16, and Table 3-14 for Year 17, summarizes all interstate and intrastate pipeline holdings and utilization during the reporting period(s).

1.8 Review of CPIM Performance

Table 1-1 below compares benchmark gas costs to actual costs of natural gas (including transportation and storage costs) in total dollars, as well as by volume, for the last three years starting from Year 15, as confirmed by DRA's examination of PG&E reports.

Table 1-1[6]

Gas Cost Comparison

	CPIM Year 17	CPIM Year 16	CPIM Year 15
Actual Gas Cost	$1,447,109,402	$ 1,213,790,799	$2,315,944,394
Benchmark Gas Cost	$1,480,687,740	$1,246,815,929	$2,379,210,822
Customer Savings	$ 17,180,947	$ 18,493,522	$ 54,889,593
Shareholder Reward	$ 4,295,237	$ 4,623,381	$ 8,376,835
Average Actual Gas Cost	$5.17/MMBtu	$4.52/MMBtu	$8.20/MMBtu
Average Benchmark Cost	$5.29/MMBtu	$4.64/MMBtu	$8.43/MMBtu

1.9 Conclusion

Based on the foregoing, DRA recommends a shareholder reward to PG&E for Year 16 of $4,623,381, and Year 17 of $4,295,234 to be recovered through PG&E's Purchased Gas Account. DRA will continue monitoring and evaluating the CPIM and collaborate with PG&E and other parties to identify any modifications needed to enhance CPIM effectiveness.

[6] Net actual volumes in CPIM Years 15, 16, and 17 were 282,388,464 MMBtus, 268,533,760 MMBtus, and 279,863,168 MMBtus, respectively.

CHAPTER 2

MONITORING AND EVALUATION AUDIT
YEAR 16

2.1 DRA's CPIM Reward Evaluation

In its submitted Core Procurement Incentive Mechanism (CPIM) Performance Report, Year 16 Application (A.96-08-043), PG&E reports on results for the period November 1, 2008 through October 31, 2009. DRA conducted a review and evaluation of PG&E's accompanying performance report. The results from this evaluation include work papers from our compilations, which are incorporated as exhibits in Appendix A.

This report filing is required to comply with the Gas Accord Decision D.97-08-055, dated August 1, 1997, which approved the CPIM method for PG&E's recovery of core gas procurement and transportation costs.[7] On August 22, 2002, the Commission issued D.02-08-070, (Gas Accord II Decision), extending the initial Gas Accord market structure including the CPIM, through 2003. On December 18, 2003, the Commission issued D.03-12-061, extending the CPIM through Year 2005, or until a revised CPIM is adopted by the Commission.

DRA's evaluation incorporates the provision of Advice Letter 2856-G, which was a revision to PG&E's gas tariffs and Purchased Gas Account pursuant to D.07-06-013. This Advice Letter was in effect as of September 1, 2007.

Table 2-1, DRA's evaluation of PG&E's CPIM Year 16 performance, shows benchmark market gas costs of $1,246,815,928 and PG&E total actual cost of natural gas of $1,213,790,801. The difference between the benchmark market gas cost and PG&E's total actual cost of natural gas results is $33,025,127 of total savings in gas costs. Results show the upper tolerance band benchmark (benchmark plus 2.0% of commodity benchmark plus reservation charges) of $1,266,632,380, and the lower tolerance band benchmark (benchmark minus 1.0% of commodity benchmark plus

[7] In D.97-08-055 (approving the Gas Accord), the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997. In this decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations starting 30 days after completion of one year of Gas Accord operations.

reservation charges) of $1,236,907,702. DRA's review shows PG&E's Year 16 savings below the lower deadband of $23,116,901, which results in ratepayer savings of $18,493,522 and a shareholder reward of $4,623,381. DRA's summary of PG&E CPIM savings for Year 16 is found in Exhibit 2-8A.

TABLE 2-1
Pacific Gas & Electric Company
Ratepayer Savings and Shareholder Award Calculation
CPIM Year 16
November 1, 2008 Through October 31, 2009

Components of CPIM Reward Calculation	
Upper Tolerance Band-Benchmark + 2.0% of Commodity	$ 1,266,632,380
Benchmark Market Costs	1,246,815,928
Lower Tolerance Band Benchmark - 1.0% of Commodity	1,236,907,702
Actual Natural Gas Costs	1,213,790,799
Benchmark Costs Less Actual Costs	33,025,129
Under (Over) Lower Tolerance Deadband	23,116,903
Ratepayers Savings Under Lower Tolerance Band	18,493,522
Shareholder Reward Earned Under Lower Tolerance Band	4,623,381
Lower Tolerance Savings @ 1%	9,908,226
Total CPIM Ratepayer Savings	18,493,522
Reconciliation of Ratepayer Savings and Shareholder Reward to Benchmark:	$ 33,025,129

2.2 Summary of Benchmark and Actual Costs

Table 2-1 summarizes gas costs, tolerance band limit, and performance results that compare it to the benchmark. The CPIM benchmark consists of three components: a) fixed transportation costs which include Canadian, U.S. interstate, and California intrastate reservation costs; b) variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs, and; c) storage costs for fixed reservation charges and variable costs. The benchmark is compared to actual gas costs, transportation costs and storage costs incurred and reported for the period.

The calculated tolerance band and related actual commodity cost of gas are measured annually against the benchmark. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the border and/or CityGate.

As of October 31, 2009, the regional average spot price for the benchmark was $5.22 (Exhibit 2-8B), based on published reports from *Natural Gas Intelligence*.

For Year 16, Table 2-1 shows annual results for actual costs of $1,213,790,801 to be less than benchmark costs of $1,246,815,928 (includes gas purchases and reservation charges). This is below the CPIM benchmark, which reflects PG&E's gas savings performance, which is below the lower limit of the tolerance band. These results provide savings to be shared between PG&E customers and shareholders. (See Exhibit 2-8A).

DRA's examination of PG&E's records for miscellaneous costs, reservation and transportation costs, and regulatory balancing accounts is performed to highlight variances in the reporting of gas costs. The sections that follow in Chapter 2 will provide a detailed review of these related costs.

2.3 Review of Benchmark Commodity and Reservation (Demand) Charges

The CPIM benchmark is based on published indices for natural gas commodity costs at PG&E's CityGate. Table 2-2 provides a breakdown by pipeline that represents PG&E's commodity resources for the period. Specifically, CPIM benchmark commodity costs are $990,822,618, a fifty-four percent (54%) decrease from prior year commodity costs and benchmark pipeline reservation charges of $255,993,311, a six percent (6%) increase. Total benchmark costs, including both commodity and reservation charges were $1,246,815,929, which reflects a forty-eight percent (48%) decrease. This decrease in commodity costs appears to reflect changes in spot prices and volume level. For example, in July 2008, spot prices were $12.00, but later in the year prices continued to decrease to $5.89 in October of the same year. Further, benchmark volume results show 254,893,032 (MMBtus) for the period, which is a nine-percent (9%) decrease from prior year.

The "upper limit" tolerance band of the benchmark, $1,266,632,380 is calculated by adding 2.0% to the commodity benchmark of $990,822,618, and adding the reservation (demand) benchmark costs of $255,933,311. The upper limit components are: a) benchmark commodity costs of $990,822,618, b) benchmark reservation charges of $255,933,311, and c) related benchmark commodity costs of $19,876,451.

TABLE 2-2 Benchmark Commodity Costs and Reservation Charges CPIM Year 16 November 1, 2008 Through October 31, 2009		
Benchmark Commodity Costs by Pipeline:	**Market Benchmark**	**Natural Gas Volume (MMBtus)**
California Firm	$1,369,968	
Kingsgate	14,549,437	
San Juan	412,456,081	
AECO	509,458,907	
Topock Firm	27,902,963	
CityGate As Available	25,085,262	
Total Benchmark Costs by Pipeline:	$990,822,618	
Benchmark Reservation Charges:		
Trans-Canada B.C. System	$10,703,956	
California Gas Transmission	100,921,111	
El Paso Natural Gas Company	22,303,284	
Lodi Gas Storage, Inc.	960,000	
Nova Gas Transmission, Ltd.	32,403,206	
Gas Transmission, Northwest Corp.	71,289,011	
Transwestern Pipeline Company	17,412,743	
Total Benchmark Reservation Charges:	$255,993,311	
Total Benchmark Commodity Costs & Reservation Charges:	$1,246,815,929	
CityGate Benchmark Gas Volume:		254,893,032
Actual Purchases by Volume:		268,533,760

2.4 Actual Natural Gas Costs

A review of actual costs for commodity purchases and reservation charges reported by PG&E is summarized in Table 2-3 by pipeline. Reservation charges include intrastate and interstate charges for Trans-Canada-B.C. System, California Gas Transmission, El Paso Natural Gas Company, Lodi Gas Storage, Inc., Nova Gas Transmission, Ltd., Gas Transmission Northwest Corporation, and Transwestern Pipeline Company.[8]

Table 2-3 shows PG&E costs of commodity purchases for interstate and intrastate at $978,313,484, which is a fifty-three percent (53%) decrease from prior year. In contrast, reservation charges for interstate and California intrastate were

[8] PG&E Annual Performance Report, CPIM Year 16, dated March 2, 2010.

$235,511,416, a five-percent (5%) increase. A comparison of total actual cost from prior year of $1,213,790,800 shows a forty-seven percent (47%) decrease from prior year. A similar trend shows actual natural gas volume (MMBtus) of 266,931,696 decreasing by five-percent (5%).

TABLE 2-3
Summary of Actual Commodity Costs & Reservation Charges
CPIM Year 16
November 1, 2008 through October 31, 2009

Actual Commodity Costs - by Pipeline:	**Actual Costs**	**Natural Gas Volume (MMBtus)**
CGT -Baja Path	$11,929,169	
CGT - CityGate	(212,956,475)	
CGT - Redwood	8,346,905	
EPNG - Basin	240,535,763	
EPNG - Topock	38,706,534	
Kern River - Daggett	342,413	
NGTL - AECO-NIT	762,886,961	
GTNC-All	(41,956,782)	
TW-Basin	173,107,375	
TW-Topock	4,060,810	
Hedging Derivative Adjustment	(34,100)	
Miscellaneous Costs & Revenues	(6,689,189)	
Total Commodity Costs:	$978,279,384	
Actual Reservation Charges:		
Trans-Canada B.C. System	$10,401,630	
California Gas Transmission	86,526,589	
El Paso Natural Gas Company	21,225,852	
Lodi Gas Storage, Inc.	960,000	
Nova Gas Transmission, Ltd.	29,573,213	
Gas Transmission Northwest	69,957,604	
Transwestern Pipeline Company	16,866,528	
Total Reservation Charges:	$235,511,416	
Net Actual Costs:	$1,213,790,800	
Total Volume:		**266,931,696**

2.5 Natural Gas Storage Costs

In accordance with D.06-07-010, a monthly distribution of winter storage withdrawals and summer storage injections is used in the calculation of the monthly benchmark purchase volumes. PG&E reports managing storage on an incremental basis so that impact to CPIM metrics can be attained and yet ensure adequate capacity is available for reliability. A schedule is used to establish daily benchmark allocations of injection and withdrawals and to ensure distributions are allocated evenly throughout the period. When it becomes necessary to balance portfolio supplies with core loads, PG&E will generally make exceptions from their planned schedules in order to meet interstate and intrastate pipeline tolerances, balancing rules, and most importantly, conservation of gas for storage and peaking requirements.[9]

For the benchmark, the storage cost component includes volumetric storage charges as well as storage reservation costs at the as-billed rate for a) 33.5 MMdth of inventory, b) 115 to 207 Mdth per day of summer injection, and c) 970 to 1,253 Mdth per day of winter withdrawal capacity, which is adjusted for core aggregation elections. The volumetric storage charges are included at the tariff rate.[10]

DRA's Exhibit 2-7D show fixed storage charges paid to California Gas Transmission (CGT) of $41,119,314, and $820,834 for incremental storage. Lodi Storage charges were $960,000 for the reporting period.

As noted in Table 2-4, a summary of storage inventory shows the status of physical inventories (measured in MMBtus) for beginning and ending balances as of October 31, 2009. PG&E reports beginning storage inventory levels as of November 1, 2008 at 31,674,687 MMBtus and ending inventory as of October 31, 2009 at 31,122,862 MMBtus. End of period injection and withdrawal levels show 30,578,137 MMBtus of injections, and 31,129,962 MMBtus of withdrawals. The reported balances are consistent with the required inventory levels of 33.5 MMdth.

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[9] PG&E Annual Performance Report, CPIM Year 16, dated March 5, 2010.

[10] The actual ratemaking treatment of the core storage reservation provides for a fully bundled cost with no variable charge. However, for CPIM calculation purposes, a variable storage cost has been assumed in order to provide an appropriate economic incentive to use storage services efficiently.

TABLE 2-4
Pacific Gas and Electric Company
Summary of Storage Inventory Injections and Withdrawals
CPIM Year 16
November 1, 2008 through October 31, 2009

Natural Gas Storage Providers	Beginning Inventory 11/01/08 (MMBtus)	Injections	Withdrawals	Ending Inventory 10/31/09 (MMBtus)
Pacific Gas & Electric	31,674,687	30,578,137	(31,129,962)	31,122,862
LODI Storage, Inc.	500,000	500,000	(500,000)	500,000
California Gas Transmission	500,000	500,000	(500,000)	500,000
Year End Storage Inventory	32,674,687	31,578,137	(32,129,962)	32,122,862

2.6 Review of Purchase Gas Account (PGA)

PG&E submitted its reconciliation of its regulatory balancing account, Purchase Gas Account (PGA). For the reporting period, PG&E's accounting entries represent the amounts expected to be received from or refunded to its customers through authorized adjustments within a twelve-month period. The PGA shows the tracking of gas related costs and revenues for recovery. The under or over collected position of this account is dependent on seasonality and volatility in gas volumes. DRA examined reconciliation entries with related PG&E CPIM documentation to identify nature and timeliness of these entries according to Advice Letter 2856-G. Table 2-5 below shows net commodity costs of $978,279,089, which agrees to supporting documentation presented in PG&E's Annual Performance Report, for actual natural gas purchases.

DRA's review of adjustments identified fixed and floating swap derivative gains subtracted from gas purchases. For this reporting period, winter hedging and related costs are not included in the CPIM. Other adjustment entries were for natural gas purchases, transport charges, reservation fees and incremental storage costs.

TABLE 2-5
Pacific Gas and Electric Company
Purchase Gas Account Review
CPIM Year 16
November 1, 2008 through October 31, 2009

CPIM Purchase Costs	Commodity Purchases	Volumetric Transportation	Subtract True-up	Add True-up	Total CPIM
EPNG, Kern River, and Transwestern (Baja Path):					
Basin	$410,952,397	2,690,742	0	0	$413,643,139
Transmission Line	43,109,756	11,929,169			55,038,925
GTNC and NGTL (Redwood Path):					
Transmission Line	718,182,732	11,094,349			729,277,081
CityGate (Mission Path)	(212,956,474)	0			(212,956,474)
Sub-Total:	959,288,411	25,714,260			985,002,671
Misc. Revenues and Expenses	(6,689,482)	0			(6,689,482)
Fixed and Floating Swaps - Hedging Gain	(34,100)				(34,100)
	$952,564,829	25,714,260	0	0	$978,279,089
Purchase Gas Account Adjustments:					
Natural Gas Field Line Purchases	410,494,702		565,535	(86,879)	410,973,358
Natural Gas Transmission Line Purchases	755,706,816		(1,209,884)	(255,442)	754,241,490
Natural Gas CityGate Purchases	(213,102,668)		216,124	222,476	(212,664,068)
Pipeline Transport Charges		26,084,331	8,416	3,111	26,095,858
Demand Fees	130,000				130,000
Incremental Storage Costs - CGT	0	(820,832)			(820,832)
Total Purchase Gas Account Adjustments:	953,228,850	25,263,499	(419,809)	(116,734)	977,955,806
Timing Differences:	($664,021)	$450,761	$419,809	$116,734	$323,283

2.7 Review of Core Pipeline Demand Charge Account (CPDCA)

PG&E submitted its reconciliation for regulatory balancing account, Core Pipeline Demand Charge Account (CPDCA). This account is used to record costs associated with backbone transmission, interstate capacity, and Canadian capacity for core procurement. DRA reviewed PG&E documentation, which shows total charges by pipeline for the period to be $235,511,412.

Balance account adjustments consist of pipeline demand charges, firm storage costs, and pipeline transport charges. Table 2-6 shows total adjustments in the amount of $235,238,610, where timing differences of $272,802 are considered nominal.

TABLE 2-6 Pacific Gas and Electric Company Review of CPDCA Balancing Account CPIM Year 16 November 1, 2008 through October 31, 2009				
Reservation Charges by Pipeline	**Reservation Charges**	**Subtract True-up**	**Add True-up**	**Total CPIM**
Alberta Natural Gas	$ 10,401,630			$ 10,401,630
California Gas Transmission	45,407,272			45,407,272
Firm Storage Costs	41,119,314			41,119,314
El Paso Natural Gas	21,225,851			21,225,851
Lodi Gas Storage	960,000			960,000
NOVA Gas Transmission	29,573,212			29,573,212
PG&E Gas Transmission N.W.	69,957,604			69,957,604
Transwestern Pipeline Company	16,866,529			16,866,529
Total Demand Charges:	$ 235,511,412			$235,511,412
CPDCA Balancing Account Adjustments:				
Pipeline Demand (Reservation) Charges	192,419,245	748,553	(8,502)	193,159,296
Firm Storage Costs	41,119,314			41,119,314
Pipeline Transport Charges	960,000	0	0	960,000
Total CPDCA	$234,498,559	748,553	(8,502)	$235,238,610
Timing Differences	$1,012,853	(748,553)	8,502	$272,802

2.8 Review of Miscellaneous Costs and Revenues

Table 2-7 shows a summary of miscellaneous costs and credits that agree with reporting from PG&E's Annual Performance Report for the period. Results show total annual miscellaneous costs and revenues at $6,689,189, which is a twenty-two percent (22%) increase from prior year. This amount is also included in the purchase gas account as part of commodity purchases.

Costs consist of broker fees of $194,934, capacity demand fees of $430,000, storage charges of $8,500, and Cochrane Extraction Revenue of $7,322,623. These revenues offset reported procurement costs and assist management in managing net costs that impact CPIM performance.

TABLE 2-7
Pacific Gas and Electric Company
Schedule of Miscellaneous Costs and Revenues
CPIM Year 16
November 1, 2008 through October 31, 2009

Month Year	Broker Fees	Demand Fees	Cochrane Extraction Revenue	OFO Charges	Usage Storage Charges	Total Misc Charges
Nov-08	$ 11,169	$ 430,000	$ (202,340)	$ -		$ 238,829
Dec-08	21,525	0	(126,191)	2,308		(102,358)
Jan-09	13,397	0	(570,101)	0		(556,704)
Feb-09	15,170	0	(555,927)	(2,308)		(543,065)
Mar-09	18,247	0	(546,445)	0		(528,198)
Apr-09	14,723	0	(866,840)	0	8,500	(843,617)
May-09	19,062	0	(934,243)	0		(915,180)
Jun-09	12,292	0	(700,737)	0		(688,446)
Jul-09	25,418	0	(540,047)	0		(514,629)
Aug-09	13,662	0	(640,497)	0		(626,835)
Sep-09	16,348	0	(649,501)	0		(633,153)
Oct-09	13,921	0	(989,754)	0		(975,833)
Totals:	$ 194,934	$ 430,000	$ (7,322,623)	$ -	$ 8,500	$ (6,689,189)

2.9 Examination of Hedging Costs Outside of CPIM

Pursuant to D.07-06-013, Advice Letter 2908-G, effective March 24, 2008, the Commission authorized PG&E's Annual Core Hedge Implementation Plan for 2008 for long term hedging for purchases of call options and swaps for a three-year period. A Settlement Agreement between PG&E, TURN, Aglet Consumer Alliance and DRA, highlights the long-term core hedge program, requirements for reporting and continuous monitoring. Section 5.1 of the Settlement Agreement requires PG&E to file two (2) compliance advice letters once after the annual implementation period and the other at the end of the winter season. As such, Advice Letter 3009-G, effective May 1, 2009, reports compliance to the Energy Division to meet its Annual Core Gas Hedging Implementation Plan requirements.

For Year 16, DRA reviewed PG&E's reconciliation documents for the Core Gas Hedging Sub-Account. Although these costs are not included in the CPIM benchmark, it does require disclosure in the Purchase Gas Account. For greater transparency DRA recommends that PG&E clearly disclose all hedging costs as entered in the Purchase Gas Account to ensure all gas purchases are recorded accurately and timely for CPIM reporting.

Commission D.07-06-013 requires PG&E to report financial options and swaps under its winter hedge plan. The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 16 were $91,214,310. As shown in Table 2-8, PG&E reported hedging activity of option premiums paid of $52,023,623, and swap losses of $39,190,687 which is not included in Year 16 costs.

Table 2-8

Winter Hedge Costs Outside the CPIM (Year 16)

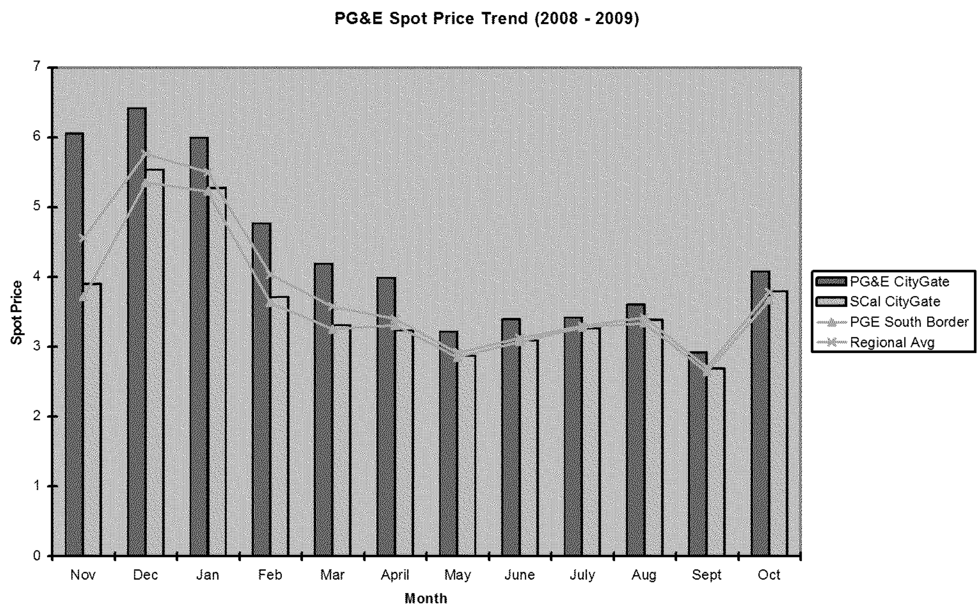
(D.07-06-013) **Option Settlements**	$52,023,623
(D.07-06-013) **Swap Settlements**	$39,190,687

For a perspective on hedging transactions, it is important to note that natural gas prices are determined through the interaction of two types of markets: cash/financial markets and physical quantities of natural gas. The market involves the purchase and sale of both where the physical quantities and financial instrument prices are connected to the price of natural gas in the physical market.

Publishers of industry newsletters such as *Platt's*, and *Natural Gas Intelligence* take surveys of the price of transactions at a hub or city-gate where natural gas is sold or delivered. The surveyed prices are calculated into an average which is reported as an index of those prices. These index prices are used to base the price of gas (spot price) at the hub, city-gate, or a specified location.

For hedging natural gas commodities, the most commonly used financial instruments are over-the-counter (OTC) and exchange derivatives often referred to as options and swaps. These financial instruments are traded in the form of standardized contracts. This standardization provides ease of transfer and the identification of prices.[11] These hedging transactions will generally incur related transaction fees, such as broker and premium fees to purchase the hedging contract. Associated transaction fees are also included based on the date of contract where net results may be a financial gain or loss. Transactions that result in gains and/or cash receipts are offset against losses. Beginning in CPIM Year 18, PG&E will report these costs in a sub-account within the purchased gas account where hedging costs will be included in the CPIM.

To provide a view of spot price activity in California for the reporting period, the following graph provides a historical trend published by *Natural Gas Intelligence* for Year 16.



2.10 Review of Sales and Volume Transactions

Table 2-9 shows PG&E total sales of $303,281,181, a forty-eight percent (48%) decrease from prior year, and reported volume of 71,993,435 MMBtus, an eleven percent (11%) increase for the same period. A breakdown by pipeline shows sales for CGT CityGate of $235,900,028, a fifty-three percent (53%) decrease, EPNG-Basin of

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[11] U.S. Senate Permanent Committee on Investigations: Excessive Speculation in the Natural Gas Market, July 9, 2007.

$4,275,962, an eight percent (8%) decrease, EPNG-Topock of $2,513,255, a seventy-five percent (75%) decrease, NGTL-AECO/NIT of $8,850,133, a fifty-nine percent (59%) decrease and GTNC-All of $46,607,920, a nine-percent decrease. The same period sales volume for CGT CityGate showed 53,206,913 MMBtus, a sixteen percent (16%) decrease, EPNG-Basin of 1,050,827 MMBtus, an eighty-seven percent (87%) increase, EPNG-Topock of 1,137,391 MMBtus, a sixteen percent (16%) increase, NGTL-AECO/NIT of 1,795,261 MMBtus, a thirty-nine percent decrease (39%), and GTNC-All of 13,606,859 MMBtus, a one-hundred twenty-three percent (123%) increase, along with new purchase activity from Transwestern Basin and Topock.

TABLE 2-9
Pacific Gas and Electric Company
Actual Sales and Volume
CPIM Year 16
November 1, 2008 through October 31, 2009

Sales by Pipeline:	Volume (MMBtus)	$ Dollars
CGT CityGate	53,206,913	$ 235,900,028
EPNG-Basin	1,050,827	4,275,962
EPNG-Topock	1,137,391	2,513,255
NGTL-AECO/NIT	1,795,261	8,850,133
GTNC-All	13,606,859	46,607,920
TW Basin	76,523	1,288,717
TW Topock	1,119,661	3,845,166
Total:	71,993,435	$ 303,281,181

2.11 Review of Reservation Charges

DRA completed a reconciliation of the benchmark to actual reservation charges reported in PG&E's Annual Performance Report for subject period to identify any variances. The results show no discrepancies, and items reported showed brokered revenues were no longer part of reservation charges. As such, the reconciliation accounts for actual reservation charges of $256,497,136, and adjustments to this amount were for discount capacity release revenue of $15,985,721, discount capacity release of $4,117,748, and other adjustments of $882,255.

Table 2-10 provides a summary of adjustments that were offset against the benchmark. Net results agree with reported actual reservations of $235,511,412.

TABLE 2-10
Pacific Gas and Electric Company
Reconciliation of Reservation Charges
CPIM Year 16
November 1, 2008 through October 31, 2009

CPIM Performance Report Benchmark Demand Charges:	**$ 255,993,310**
Actual Demand Charges by Pipeline System:	
Canadian	43,107,162
Interstate	112,468,863
Intrastate	100,921,111
Total Actual Demand Charges:	$256,497,136
Add (Deduct) Discount Capacity Release Revenue:	
Canadian Capacity	(5,882,867)
Interstate Capacity	(2,576,626)
Intrastate Capacity	(7,526,228)
Total Discount Capacity Release Revenue:	($15,985,721)
Discounted (Premium) Capacity Release:	
Canadian	2,750,549
Intrastate	(6,868,297)
Total Discounted (Premium) Capacity Release:	($4,117,748)
Other Cost Adjustments:	
Interstate:	
Reservation Charge Discount	(548,930)
Injection/Withdrawal Charges	(333,325)
Total Other Cost Adjustments:	($882,255)
Reconciliation of Reservation Charges - Actual	**$235,511,412**

2.12 Review of Interstate Pipeline Capacity Purchases

PG&E reported contract changes of interstate pipeline capacity for El Paso Natural Gas (EPNG) long and short-term contracts for the reporting period. Per Advice Letter 3064-G, effective December 11, 2009, PG&E was authorized to renew its capacity holdings for annual and winter utilization. The following table provides a summary of contract terms.

Pipeline	Contract Duration	Contract Term	Volume (MDth/d)
EPNG	Long-Term	07/01/10 - 06/30/12	116,035
EPNG	Long-Term	07/01/10 - 06/30/12	85,739
EPNG	Short-Term	12/01/08 - 02/28/09	65,000

2.13 Review of Volumetric Transport Costs

Table 2-11 provides a summary of PG&E's reported volumetric transportation costs by pipeline. Trends in transport activity appear to be consistent with purchase and sales transactions. Changes from last year activity shows that California Producers were not used for transportation for this reporting period.

The total volumetric transport costs were $25,714,260, a five-percent (5%) decrease from prior year. In addition, costs were broken down by pipeline to identify changes such as CGT-Baja reported $11,929,169 in costs, which is a three-percent (3%) decrease, CGT-Redwood was $8,346,905, a nine-percent (9%) decrease, EPNG-Basin of $2,036,551, a twenty-two percent (22%) decrease, NGTL-AECO/NIT of $562,879, a one-hundred fifty eight percent (158%) increase, GTNC-All of $2,184,565, a six percent (6%) decrease, and Transwestern-Basin of $654,191, an eight-percent (8%) percent increase. These costs are included in the CPIM and are part of the reconciliation of the PGA balancing account.

TABLE 2-11
Pacific Gas and Electric Company
Commodity Volumetric Transport Costs
CPIM Year 16
November 1, 2008 through October 31, 2009

CGT-Baja	$ 11,929,169
CGT-Redwood	8,346,905
EPNG-Basin	2,036,551
NGTL-AECO/NT	562,879
GTNC-ALL	2,184,565
TW-Basin	654,191
Total Volumetric Transport Costs:	$ 25,714,260

2.14 Review of Benchmark Commodity Indices

Table 2-12 provides a summary of PG&E's CityGate indices used to calculate the benchmark of monthly commodity costs. These indices are reported to *Natural Gas Intelligence*, which publishes them in their gas price index. As such, these indices were applied to the CityGate benchmark volume reported at 254,893,032 MMBtus (shown in Table 2-2) to determine the commodity benchmark costs of $990,822,618. DRA compilations show the commodity benchmark cost, plus the benchmark reservation charges of $255,993,311 results in the total market benchmark costs for Year 16 of $1,246,815,928.

The Canadian benchmark commodity indices are established using the exchange rates in effect when the indices are issued prior to the availability of closing currency exchange rates. However, the final indices, which determine the actual gas supply prices, reflect closing exchange rates.

For Year 16, PG&E's gas operations apply a pipeline sequencing methodology for purposes of purchasing gas at the lowest cost. However, PG&E has the discretion to change the sequence in pipeline selection at any time in order to meet reliability requirements.

TABLE 2-12 Pacific Gas and Electric Company PG&E City Gate Indices CPIM Year 16 November 1, 2008 through October 31, 2009					
Month Year	**California Topock (Firm)**	**Kingsgate**	**San Juan**	**AECO**	**(End of Month) PG&E CityGate NGI Daily**
Nov-08	$3.859297	$6.019305	$3.052942	$5.823765	$6.44
Dec-08	5.510766	6.408827	4.912067	6.208469	6.08
Jan-09	5.388286	5.876059	5.118890	5.666160	4.66
Feb-09	3.767212	4.928582	3.332469	4.724671	4.06
Mar-09	3.382206	4.194787	2.896249	3.990205	3.53
Apr-09	3.442997	3.731779	2.823546	3.520684	3.39
May-09	2.976938	3.439636	2.698912	3.212723	3.33
Jun-09	3.199836	3.433037	2.854705	3.213743	3.69
Jul-09	3.412602	3.435283	3.197449	3.201825	3.50
Aug-09	3.473392	3.237091	3.405172	3.001195	2.90
Sep-09	2.764172	2.913357	2.667754	2.675389	4.02
Oct-09	3.807738	3.275977	3.654642	3.035086	5.22

2.15 Examination of Fixed Storage and Transportation Costs

Pursuant to Advice Letter 2856-G, PG&E reported its benchmark reservation (demand) and fixed storage charges. Based on this report, DRA reviewed the costs and identified changes in activity from prior year report. The total transportation and storage costs of $255,993,311, results in a six-percent (6%) increase from prior year. The Canadian pipeline transactions of $43,107,162, shows a thirteen-percent (13%) decrease. U.S. interstate was $111,005,038, a twenty-seven percent (27%) increase, California intrastate shows $58,980,963, a three-percent (3%) decrease, and intrastate fixed and incremental storage costs were $42,900,148, a nominal one-percent (1%) change. Table 2-13 provides a summary of these costs.

TABLE 2-13 Pacifc Gas and Electric Company Summary of Fixed Transport and Storage Costs CPIM Year 16 November 1, 2008 through October 31, 2009	
Canadian Pipelines:	**$**
Foothills Pipelines	10,703,956
Nova Gas Transmission Ltd.	32,403,206
Total Canadian Pipeline Costs:	$43,107,162
U.S. Interstate Pipelines:	
Gas Transmission Northwest Corp.	71,289,011
El Paso Natural Gas	22,303,284
Transwestern Pipeline Company	17,412,743
Total U.S. Interstate Pipeline Costs:	$111,005,038
CA Intrastate Pipelines:	
CGT- Baja	36,194,767
CGT-Redwood	22,748,752
CGT-Silverado	37,444
Total CA Intrastate Pipeline Costs:	$58,980,963
CA Intrastate Storage Costs:	
CGT Firm Contracts	41,119,314
CGT Incremental Contracts	820,834
Lodi Contracts	960,000
Total CA Storage Costs:	$42,900,148
Total Transportation & Storage Costs:	$255,993,311

2.16 Utilization of Firm Interstate and Intrastate Pipeline Assets

PG&E has short and long term contracts for purchases of natural gas resources transported from Canadian, U.S. interstate and California intrastate pipeline systems to meet core gas demand. During Year 16, PG&E transported these resources using firm transportation contracts. Table 2-14 shows PG&E's estimated utilization for the period and notes changes in contract activity from prior year.

PG&E estimates utilization proportionally based on capacity available to transport supplies and/or releases to other parties. To benefit core users, PG&E was authorized to increase the annual Baja Path core capacity and decrease capacity allocated to the Silverado Path. By increasing the Baja Path capacity encourages purchases of natural gas where prices are deemed to be more competitive, as well as, match the upstream firm capacity on the southwest interstate pipelines.[12] Additionally, PG&E is authorized to recover the costs associated with its Canadian and US interstate capacity through approval procedures specified in D.04-09-022.[13] Pursuant to D.07-07-002, PG&E can also allocate firm intrastate capacity and recover associated costs. D.07-07-002 also eliminated the November to March seasonal Baja capacity and increased the annual firm Baja capacity from 155 MDth/d to 348 Dth/day as reported in PG&E's Table III of their CPIM Performance Report.[14]

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[12] D.07-07-002, Opinion Regarding the Request to Change the Allocations of Firm Backbone Pipeline Capacity and Related Charges, p. 6.

[13] D.04-09-022, Rulemaking to Establish Policies and Rules to Ensure Reliable Long Term Supplies of Natural Gas to California.

[14] PG&E Annual Report, CPIM Year 16, PG&E Table III,

Table 2-14
Pacific Gas and Electric Company
Core Gas Supply - Utilization of Interstate, Intrastate and Canadian Pipeline Assets
CPIM Year 16
November 1, 2008 through October 31, 2009

Pipeline Capacity:	Quantity (Dth/d)	Contract Expiration Date	Utilization Rate	Change from Prior Year Capacity
TransCanada Pipelines:				
NOVA	595,934	10/31/11		
	23,435	10/31/11		
Total NOVA:	619,369		100%	0%
Foothills-BC System	587,761	10/31/11		
	23,293	10/31/11		
Total Foothills-BC System:	611,054		100%	0%
Interstate Pipelines:				
Gas Transmission Northwest	250,000	10/31/11		
	279,968	10/31/16		
	80,000	10/31/20		
Total Gas Transmission Northwest:	609,968		96%	-1%
El Paso Natural Gas	116,035	06/30/12		
	85,739	06/30/13		
	65,000	02/28/09		
Total El Paso Natural Gas:	266,774		98%	0%
Transwestern Pipeline Co.	150,000	03/31/11		
	30,000	02/28/09		
	25,000	01/31/09		
Total Transwestern Pipeline Co:	205,000		97%	1%
Intrastate Pipelines:				
Silverado Path	1,000	No expiration	100%	84%
Redwood Path	608,766	No expiration	100%	100%
Baja Path	348,000	No expiration		
	321,000	No expiration		
Total Baja Path Capacity:	669,000		97%	4%

CHAPTER 3
MONITORING AND EVALUATION AUDIT
YEAR 17

3.1 DRA's CPIM Reward Evaluation

In its submitted Core Procurement Incentive Mechanism (CPIM) Performance Report, Year 17 Application (A.96-08-043), PG&E reports on results for the period November 1, 2009 through October 31, 2010. DRA conducted a review and evaluation of PG&E's accompanying performance report. The results from this evaluation include work papers from our compilations, which are incorporated as exhibits in Appendix A.

This report filing is required to comply with the Gas Accord Decision D.97-08-055, dated August 1, 1997, which approved the CPIM method for PG&E's recovery of core gas procurement and transportation costs.[15] On August 22, 2002, the Commission issued D.02-08-070, (Gas Accord II Decision), extending the initial Gas Accord market structure including the CPIM, through 2003. On December 18, 2003, the Commission issued D.03-12-061, extending the CPIM through Year 2005, or until a revised CPIM is adopted by the Commission.

DRA's evaluation incorporates the provision of Advice Letter 2856-G, which was a revision to PG&E's gas tariffs and Purchased Gas Account pursuant to D.07-06-013. This Advice Letter was in effect as of September 1, 2007.

Table 3-1, DRA's evaluation of PG&E's CPIM Year 17 performance, shows benchmark market gas costs of $1,480,687,740 and PG&E total actual cost of natural gas of $1,447,109,402. The difference between the benchmark market gas cost and PG&E's total actual cost of natural gas results is $33,578,338 of total savings in gas costs. Results show the upper tolerance band benchmark (benchmark plus 2.0% of commodity benchmark plus reservation charges) at $1,504,892,048, and the lower tolerance band benchmark (benchmark minus 1.0% of commodity benchmark plus reservation charges) at $1,468,585,586. DRA's review shows PG&E's Year 17

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[15] In D.97-08-055 (approving the Gas Accord), the Commission approved a CPIM mechanism for core gas costs incurred after December 31, 1997. In this decision, the Commission ordered PG&E to file quarterly and annual reports on core procurement operations starting 30 days after completion of one year of Gas Accord operations.

savings below the lower deadband of $21,476,184, which results in ratepayer savings of $17,180,947 and a shareholder reward of $4,295,237. DRA's summary of PG&E CPIM savings for Year 17 is found in Exhibit 3-8A.

TABLE 3-1
Pacific Gas & Electric Company
Ratepayer Savings and Shareholder Award Calculation
CPIM Year 17
November 1, 2009 Through October 31, 2010

Components of CPIM Reward Calculation	
Upper Tolerance Band-Benchmark + 2.0% of Commodity	$ 1,504,892,048
Benchmark Market Costs	1,480,687,740
Lower Tolerance Band Benchmark - 1.0% of Commodity	1,468,585,586
Actual Natural Gas Costs	1,447,109,402
Benchmark Costs Less Actual Costs	33,578,338
Under (Over) Lower Tolerance Deadband	21,476,184
Ratepayers Savings Under Lower Tolerance Band	17,180,947
Shareholder Reward Earned Under Lower Tolerance Band	4,295,237
Lower Tolerance Savings @ 1%	12,102,154
Total CPIM Ratepayer Savings	17,180,947
Reconciliation of Ratepayer Savings and Shareholder Reward to Benchmark:	$ 33,578,338

3.2 Summary of Benchmark and Actual Costs

Table 3-1 summarizes gas costs, tolerance band limit, and performance results that compare it to the benchmark. The CPIM benchmark consists of three components: a) fixed transportation costs which include Canadian, U.S. interstate, and California intrastate reservation costs; b) variable costs which include commodity costs, Canadian, U.S. interstate, and California intrastate pipeline fuel and volumetric capacity costs, and; c) storage costs for fixed reservation charges and variable costs. The benchmark is compared to actual gas costs, transportation costs and storage costs incurred and reported for the period.

The calculated tolerance band and related actual commodity cost of gas are measured annually against the benchmark. The benchmark is based on the prevailing published natural gas price indices for gas delivered from the border and/or CityGate. As of October 31, 2010, the regional average spot price for the benchmark was $3.93 (Exhibit 3-8B), based on published reports from *Natural Gas Intelligence*.

For Year 17, Table 3-1 shows annual results for actual costs of $1,447,109,402 to be less than benchmark costs of $1,480,687,740 (includes gas purchases and reservation charges). This is below the CPIM benchmark, which reflects PG&E's gas savings performance, which is below the lower limit of the tolerance band. These results provide savings to be shared between PG&E customers and shareholders. (See Exhibit 3-8A).

DRA's examination of PG&E's records for miscellaneous costs, reservation and transportation costs, and regulatory balancing accounts is performed to highlight variances in the reporting of gas costs. The sections that follow in Chapter 3 will provide a detailed review of these related costs.

3.3 Review of Benchmark Commodity and Reservation (Demand) Charges

The CPIM benchmark is based on published indices for natural gas commodity costs at PG&E's CityGate. Table 3-2 provides a breakdown by pipeline that represents PG&E's commodity resources for the period. Specifically, CPIM benchmark commodity costs are $1,210,315,414, a twenty-two percent (22%) increase from prior year natural gas market commodity costs and benchmark pipeline demand charges of $270,472,329, a six percent (6%) increase. Total benchmark costs, including both commodity and demand charges were $1,480,787,743, which reflects a nineteen percent (19%) increase. The increase in commodity costs appears to reflect the increase in volume activity, despite natural gas spot prices being reported for November 2009 at $4.32 and continued to decrease to $3.93 in October 2010. Further, benchmark volume results in 266,731,852 (MMBtus) for the period, which is a five-percent (5%) increase from prior year.

The "upper limit" tolerance band of the benchmark, $1,504,892,048 is calculated by adding 2.0% to the commodity benchmark of $1,210,215,414, and adding the reservation (demand) benchmark costs of $270,472,329. The upper limit components are: a) benchmark commodity costs of $1,210,215,414, b) benchmark reservation charges of $270,472,329, and c) related benchmark commodity costs of $60,204,305.

TABLE 3-2 Pacific Gas and Electric Company Benchmark Commodity Costs and Demand Charges CPIM Year 17 November 1, 2009 Through October 31, 2010		
Benchmark Commodity Costs by Pipeline:	**Market Benchmark**	**Natural Gas Volume (MMBtus)**
California Firm	$1,674,192	
Kingsgate	17,342,040	
San Juan	364,429,216	
AECO	768,741,816	
Topock Firm	17,362,163	
CityGate As Available	40,765,987	
Total Benchmark Costs by Pipeline:	$1,210,315,414	
Benchmark Reservation Charges:		
Trans-Canada B.C. System	$16,484,007	
California Gas Transmission	100,278,479	
Kern River Gas Transmission Refund	(8,392)	
El Paso Natural Gas Company	19,944,319	
Lodi Gas Storage, Inc.	909,000	
Nova Gas Transmission, Ltd.	41,657,159	
Gas Transmission, Northwest Corp.	71,289,011	
Transwestern Pipeline Company	19,918,746	
Total Benchmark Reservation Charges:	$270,472,329	
Total Benchmark Commodity Costs & Reservation Charges:	$1,480,787,743	
CityGate Benchmark Gas Volume:		266,731,852
Actual Purchases by Volume:		279,863,168

3.4 Actual Natural Gas Costs

A review of actual costs for commodity purchases and reservation charges reported by PG&E is summarized in Table 3-3 by pipeline. Reservation charges include intrastate and interstate charges for Foothills Pipelines, Ltd., California Gas Transmission, El Paso Natural Gas Company, Lodi Gas Storage, Inc., Nova Gas Transmission, Ltd., Gas Transmission Northwest Corporation, and Transwestern Pipeline Company.[16]

Table 3-3 shows PG&E costs of commodity purchases for interstate and intrastate at $1,190,723,925 which is a twenty-two percent (22%) increase from prior year, and similarly, reservation charges were $256,380,000, a nine-percent (9%)

[16] PG&E Annual Performance Report, CPIM Year 17, dated March 16, 2011.

increase. A comparison of total actual cost from prior year of $1,447,103,925 shows a nineteen percent (19%) increase from prior year. A similar trend shows actual natural gas volume (MMBtus) of 279,863,168, increasing five-percent (5%) from prior year activity.

TABLE 3-3
Pacific Gas and Electric Company
Summary of Actual Commodity Costs & Reservation Charges
CPIM Year 17
November 1, 2009 through October 31, 2010

Actual Commodity Costs - by Pipeline:	**Actual Costs**	**Natural Gas Volume (MMBtus)**
CGT -Baja Path	$9,945,458	
CGT - CityGate	(152,722,942)	
CGT - Redwood	9,281,483	
EPNG - Basin	245,517,707	
EPNG - Topock	25,033,099	
Kern River - Daggett	640,357	
NGTL - AECO-NIT	882,557,478	
GTNC-All	(41,330,960)	
TW-Basin	206,181,094	
TW-Topock	17,424,356	
Miscellaneous Costs & Revenues	(11,803,205)	
Total Commodity Costs:	$1,190,723,925	
Actual Reservation Charges:		
Foothills Pipelines, Ltd.	$16,155,380	
California Gas Transmission	92,226,118	
El Paso Natural Gas Company	20,499,625	
El Paso and Kern River Refunds	(1,829,384)	
Lodi Gas Storage, Inc.	909,000	
Nova Gas Transmission, Ltd.	39,460,733	
Gas Transmission Northwest	70,456,835	
Transwestern Pipeline Company	18,501,693	
Total Reservation Charges:	$256,380,000	
Net Actual Costs:	$1,447,103,925	
Total Volume:		**279,863,168**

3.5 Natural Gas Storage Costs

In accordance with D.06-07-010; a monthly distribution of winter storage withdrawals and summer storage injections is used in the calculation of the monthly benchmark purchase volumes. PG&E reports managing storage on an incremental basis so that impact to CPIM metrics can be attained and yet ensure adequate capacity is available for reliability. A schedule is used to establish daily benchmark allocations of injection and withdrawals and to ensure distributions are allocated evenly throughout the period. When it becomes necessary to balance portfolio supplies with core loads, PG&E will generally make exceptions from their planned schedules in order to meet interstate and intrastate pipeline tolerances, balancing rules, and most importantly, conservation of gas for storage and peaking requirements.[17]

For the benchmark, the storage cost component includes volumetric storage charges as well as storage reservation costs at the as-billed rate for a) 33.5 MMdth of inventory, b) 115 to 207 Mdth per day of summer injection, and c) 970 to 1,253 Mdth per day of winter withdrawal capacity, which is adjusted for core aggregation elections. The volumetric storage charges are included at the tariff rate.[18]

DRA's Exhibit 3-7D show fixed storage charges paid to California Gas Transmission (CGT) of $40,694,513, and $800,004 for incremental storage. Lodi Storage charges were $909,000 for the reporting period.

As noted in Table 3-4, a summary of storage inventory shows the status of physical inventories (measured in MMBtus) for beginning and ending balances as of October 31, 2010. PG&E reports beginning storage inventory levels as of November 1, 2009 at 31,122,862 MMBtus and ending inventory as of October 31, 2010 at 30,905,476 MMBtus. End of period Injection and withdrawal levels show 30,363,509 MMBtus of injections, and 30,580,895 MMBtus of withdrawals. The reported balances

[17] PG&E Annual Performance Report, CPIM Year 17, dated March 16, 2011.

[18] The actual ratemaking treatment of the core storage reservation provides for a fully bundled cost with no variable charge. However, for CPIM calculation purposes, a variable storage cost has been assumed in order to provide an appropriate economic incentive to use storage services efficiently.

are consistent with the required inventory levels of 33.5 MMdth.

TABLE 3-4
Pacific Gas and Electric Company
Summary of Storage Inventory Injections and Withdrawals
CPIM Year 17
November 1, 2009 through October 31, 2010

Natural Gas Storage Providers	Beginning Inventory 11/01/09 (MMBtus)	Injections	Withdrawals	Ending Inventory 10/31/10 (MMBtus)
Pacific Gas & Electric	31,122,862	30,363,509	(30,580,895)	30,905,476
LODI Storage, Inc.	500,000	450,000	(450,000)	500,000
California Gas Transmission	500,000	500,000	(500,000)	500,000
Year End Storage Inventory	32,122,862	31,313,509	(31,530,895)	31,905,476

3.6 Review of Purchase Gas Account (PGA)

PG&E submitted its reconciliation of its regulatory balancing account, Purchase Gas Account (PGA). For the reporting period, PG&E's accounting entries represent amounts expected to be received from or refunded to PG&E's customers through authorized adjustments within a twelve-month period. The PGA shows the tracking of gas related costs and revenues for recovery. The under or over collected position of this account is dependent on seasonality and volatility in gas volumes. DRA examined reconciliation entries with related PG&E CPIM documentation to identify nature and timeliness of recorded entries according to Advice Letter 2856-G. Table 3-5 below shows net commodity costs of $1,190,729,064, which also agrees to support documentation presented in PG&E's Performance Report, for actual natural gas purchases.

DRA's review of adjustments identified prior period adjustments for refunds to customers of $48,388,608, from Sempra and price indexing civil litigation settlements. Other adjustment entries were for timing differences for natural gas purchases, transport charges, and incremental storage costs.

TABLE 3-5
Pacific Gas and Electric Company
Purchase Gas Account Review
CPIM Year 17
November 1, 2009 through October 31, 2010

CPIM Purchase Costs	**Commodity Purchases**	**Volumetric Transportation**	**Subtract True-up**	**Add True-up**	**Total CPIM**
EPNG, Kern River, and Transwestern (Baja Path):					
Basin	$466,397,823	2,132,792	0	0	$468,530,615
Transmission Line	26,267,077	9,945,458			36,212,535
GTNC and NGTL (Redwood Path):					
Transmission Line	838,682,889	11,825,093			850,507,982
CityGate (Mission Path)	(152,722,942)	0			(152,722,942)
	1,178,624,847	23,903,343			1,202,528,190
Misc. Revenues and Expenses	(11,799,126)	0			(11,799,126)
Sub-Total:	$1,166,825,721	23,903,343	0	0	$1,190,729,064
Purchase Gas Account Adjustments:					
Natural Gas Field Line Purchases	466,438,673		86,879	(97,016)	466,428,536
Natural Gas Transmission Line Purchases	804,158,410		255,442	(659,762)	803,754,090
Natural Gas CityGate Purchases	(151,829,968)		(222,476)	295,861	(151,756,583)
Pipeline Transport Charges		24,706,514	(3,111)	2,100	24,705,503
Incremental Storage Costs - CGT	0	(800,004)			(800,004)
Prior Period Adjustment (1)	48,388,608				48,388,608
Total Purchase Gas Account Adjustments:	1,167,155,723	23,906,510	116,734	(458,817)	1,190,720,150
Timing Differences:	($330,002)	($3,167)	($116,734)	$458,817	$8,914

Footnote:
(1) Gas refund for Sempra and Price Indexing litigation settlements allocated to PG&E gas customers.

3.7 Review of Core Pipeline Demand Charge Account (CPDCA)

PG&E submitted its reconciliation for regulatory balancing account Core Pipeline Demand Charge Account (CPDCA). This account is used to record costs associated with backbone transmission, interstate capacity, and Canadian capacity for core procurement. DRA reviewed PG&E documentation, which shows total charges by pipeline for the period to be $256,380,000.

Balance account adjustments reflect timing differences for pipeline demand charges, firm storage costs, and pipeline transport charges. Table 3-6 shows total adjustments were $255,586,885, showing net timing differences of $793,115.

TABLE 3-6 Pacific Gas and Electric Company Review of CPDCA Balancing Account CPIM Year 17 November 1, 2009 through October 31, 2010

Reservation Charges by Pipeline	Reservation Charges	Subtract True-up	Add True-up	Total CPIM
Alberta Natural Gas	$ 16,155,380			$ 16,155,380
California Gas Transmission	51,531,861			51,531,861
Firm Storage Costs	40,694,257			40,694,257
El Paso Natural Gas	18,678,633			18,678,633
Kern River Gas Transmission	(8,392)			(8,392)
Lodi Gas Storage	909,000			909,000
NOVA Gas Transmission	39,460,733			39,460,733
PG&E Gas Transmission N.W.	70,456,835			70,456,835
Transwestern Pipeline Company	18,501,693			18,501,693
Total Demand Charges:	$ 256,380,000			$256,380,000
CPDCA Balancing Account Adjustments:				
Pipeline Demand Charges	214,385,753	8,502	36,184	214,430,439
Firm Storage Costs	40,694,513			40,694,513
Pipeline Transport Charges	909,000	0	0	909,000
EPNG & TW Reservation Discount	(447,067)			(447,067)
Total CPDCA	$255,542,199	8,502	36,184	$255,586,885
Timing Differences	$837,801	(8,502)	(36,184)	$793,115

3.8 Review of Miscellaneous Costs and Revenues

Table 3-7 shows a summary of miscellaneous costs and credits that agree with reporting from PG&E's Performance Report for the period. Results show total annual miscellaneous costs and revenues at $11,797,705, which is a seventy-six percent (76%) increase from prior year. This amount is also included in the purchase gas account as part of commodity purchases.

Costs consist of broker fees of $213,246, Cochrane Extraction Revenue of $12,316,451, operational flow order charges of $300,000, and storage related costs of $5,500. The net results of revenues offset costs which assist management in managing net costs that impact CPIM performance.

TABLE 3-7 Pacific Gas and Electric Company Schedule of Miscellaneous Costs and Revenues CPIM Year 17 November 1, 2009 through October 31, 2010

Month Year	Broker Fees	Demand Fees	Cochrane Extraction Revenue	OFO Charges	Usage Storage Charges	Total Misc Charges
Nov-09	$ 12,346	$ 4,653	$ (1,088,227)	$ 300,000		$ (771,228)
Dec-09	11,854	(4,653)	(1,142,200)	0		(1,134,999)
Jan-10	14,567	0	(1,216,958)	0		(1,202,391)
Feb-10	21,199	0	(1,090,247)	0		(1,069,048)
Mar-10	16,737	0	(1,176,324)	0	2,500	(1,157,087)
Apr-10	17,705	0	(1,125,672)	0	0	(1,107,967)
May-10	28,700	0	(1,054,072)	0	3,000	(1,022,372)
Jun-10	21,796	0	(1,111,902)	0		(1,090,106)
Jul-10	14,048	0	(765,955)	0		(751,907)
Aug-10	17,216	0	(843,902)	0		(826,686)
Sep-10	19,480	0	(439,206)	0		(419,726)
Oct-10	17,598	0	(1,261,786)	0		(1,244,188)
Totals:	$ 213,246	$ -	$ (12,316,451)	$ 300,000	$ 5,500	$ (11,797,705)

3.9 Examination of Hedging Costs Outside of CPIM

Pursuant to Advice Letter(s) 3054-G, effective November 16, 2009 and 3105-G, effective April 26, 2010, PG&E files compliance reports for its Annual Core Hedge Implementation Plan for 2009 winter and long-term hedging. Further, PG&E is authorized to purchase call options and swaps for natural gas purchases. Advice Letter 3198-G, effective April 28, 2011, requires PG&E to submit hedging results for continuous monitoring by the Energy Division.

For Year 17, DRA procedures reviewed PG&E's reconciliation documents for the Core Gas Hedging Sub-Account. Our results show inconsistencies in PG&E reporting to determine the total the total hedging costs that were flowed through to the ratepayer. Although these costs are not included in the CPIM benchmark, it does require disclosure in the Purchase Gas Account. Therefore, for greater transparency DRA recommends the end of period hedging cost balance be entered in the Purchase Gas Account to ensure all gas purchases are recorded accurately and timely for CPIM reporting.

Commission D.07-06-013 requires PG&E to report financial options and swaps under its winter hedge plan. The total hedge premiums and swap losses recorded and recovered from PG&E ratepayers for Year 17 were $86,340,406. As shown in Table 3-8, PG&E reported hedging activity of option premiums paid of $23,761,116, and swap settlements of $62,579,290 which is not included in Year 17 costs.

Table 3-8

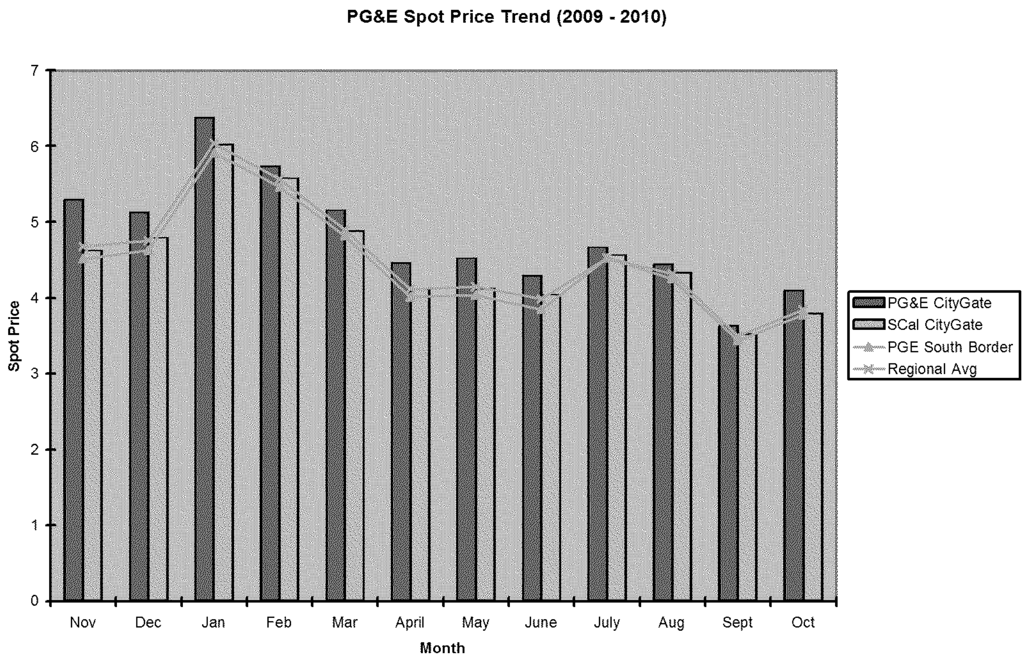
Winter Hedge Costs Outside the CPIM (Year 17)

(D.07-06-013) **Option Settlements**	$23,761,116
(D.07-06-013) **Swap Settlements**	$62,579,290

As noted previously in Section 2.9, the most commonly used financial instruments are over-the-counter (OTC) and exchange derivatives often referred to as options and swaps. These financial instruments are traded in the form of standardized contracts. This standardization provides ease of transfer and for the identification of prices.[19] These hedging transactions will generally incur related transaction fees, such as broker and premium fees to purchase the hedging contract. Associated transaction fees are also included based on the date of contract where net results may be a financial gain or loss. Transactions that result in gains and/or cash receipts are offset against losses. Beginning in CPIM Year 18, PG&E will report these costs in a sub-account of the purchased gas account where costs will be included in the CPIM.

[19] U.S. Senate Permanent Committee on Investigations: Excessive Speculation in the Natural Gas Market, July 9, 2007.

To provide a view of spot price activity in California for the reporting period, the following graph provides a historical trend published by *Natural Gas Intelligence* for Year 17.



3.10 Review of Sales and Volume Transactions

Table 3-9 shows PG&E total sales of $264,522,539, a thirteen percent (13%) decrease from prior year, and a reported volume of 57,195,599 MMBtus, a twenty percent (20%) decrease. A breakdown by pipeline shows sales for CGT CityGate of $182,065,506, a twenty-three percent (23%) decrease, EPNG-Basin of $13,535,213, a two hundred sixteen percent (216%) increase, EPNG-Topock of $11,956,070, a three hundred seventy-five percent (375%) increase, NGTL-AECO/NIT of $1,893,303, a seventy-nine percent (79%) decrease and GTNC-All of $45,804,921, a two-percent (2%) decrease. For Transwestern-Basin, sales were for $2,999,933, a one hundred thirty two percent (132%) increase, and Transwestern-Topock was $6,267,593, a sixty-three percent (63%) increase.

The same period sales volume for CGT CityGate showed 38,774,419 MMBtus, a twenty-seven percent (27%) decrease, EPNG-Basin of 2,985,379 MMBtus, a one-hundred eighty four percent (184%) increase, EPNG-Topock of 2,754,436 MMBtus, a one-hundred forty two percent (142%) increase, NGTL-AECO/NIT of 449,282 MMBtus, a seventy-five percent decrease (75%), and GTNC-All of 10,401,758 MMBtus, a thirty-three percent (33%) decrease, Transwestern Basin of 668,325 MMBtus, a seven hundred seventy three percent (773%) increase and Transwestern Topock of 1,162,000 MMBtus, a four percent (4%) increase from prior year.

Table 3-9
Pacific Gas and Electric Company
Actual Sales and Volume
CPIM Year 17
November 1, 2009 through October 31, 2010

Sales by Pipeline:	Volume (MMBtus)	$ Dollars
CGT CityGate	38,774,419	$ 182,065,506
EPNG-Basin	2,985,379	13,535,213
EPNG-Topock	2,754,436	11,956,070
NGTL-AECO/NIT	449,282	1,893,303
GTNC-All	10,401,758	45,804,921
TW Basin	668,325	2,999,933
TW Topock	1,162,000	6,267,593
Total:	57,195,599	$ 264,522,539

3.11 Review of Reservation Charges

DRA completed a reconciliation of the benchmark to actual reservation charges reported in PG&E's Annual Performance Annual Report for subject period to identify any variances. As such, the reconciliation accounts for actual reservation charges of $272,292,716, and adjustments to this amount were for discount capacity release revenue of $15,035,334, discount capacity release of $1,377,589, and other adjustments of $2,254,972. Results show no discrepancies.

Table 3-10 provides a summary of adjustments that were offset against the benchmark. Net results agree with reported actual reservations of $256,379,999.

TABLE 3-10
Pacific Gas and Electric Company
Reconciliation of Reservation Charges
CPIM Year 17
November 1, 2009 through October 31, 2010

CPIM Performance Report Benchmark Demand Charges:	**$ 270,472,326**
Actual Demand Charges by Pipeline System:	
Canadian	58,141,166
Interstate	113,873,068
Intrastate	100,278,482
Total Actual Demand Charges:	$272,292,716
Add (Deduct) Discount Capacity Release Revenue:	
Canadian Capacity	(4,057,502)
Interstate Capacity	(3,080,329)
Intrastate Capacity	(7,897,503)
Total Discount Capacity Release Revenue:	($15,035,334)
Discounted (Premium) Capacity Release:	
Canadian	1,532,448
Intrastate	(154,859)
Total Discounted (Premium) Capacity Release:	$1,377,589
Other Cost Adjustments:	
Interstate:	
Reservation Charge Discount	(434,588)
Refund Adjustments	(1,829,384)
Injection/Withdrawal Charges	9,000
Total Other Cost Adjustments:	($2,254,972)
Reconciliation of Reservation Charges - Actual	**$256,379,999**

3.12 Review of Interstate Pipeline Capacity Changes

PG&E reported contract changes of interstate pipeline capacity for Canadian pipelines: NOVA, and Foothills, and U.S. based Transwestern Pipelines. The contracts identified were for long and short-term in duration. Per Advice Letter(s) 3100-G, effective March 26, 2010, and 3153-G, effective October 15, 2010, PGE was authorized to renew its capacity holdings for annual and winter utilization. The following table provides a summary of contract terms.

Pipeline	Contract Duration	Contract Term	Volume (MDth/d)
NOVA	Long-Term	01/01/10 - 10/31/11	249,401
NOVA	Long-Term	11/01/11 - 10/31/16	287,745
NOVA	Long-Term	11/01/11 - 10/31/16	82,223
Foothills - BC System	Long-Term	11/01/09 - 10/31/11	244,860
Foothills - BC System	Long-Term	11/01/11 - 10/31/16	284,810
Foothills - BC System	Long-Term	11/01/11 - 10/31/20	81,384
Transwestern	Long-Term	04/01/11 - 03/31/13	150,000
Transwestern	Short-Term	12/01/09 - 02/28/10	76,720
Transwestern	Short-Term	12/01/10 - 02/28/11	26,720
Transwestern	Short-Term	12/01/11 - 02/29/12	43,220

3.13 Review of Volumetric Transport Costs

Table 3-11 provides a summary of PG&E's reported volumetric transportation costs by pipeline. Trends in transport activity appear to be consistent with purchase and sales transactions.

The total volumetric transport costs for the period were $23,903,342, a seven percent (7%) decrease from prior year. In addition, costs were broken down by pipeline to identify changes where CGT-Baja reported $9,945,458 in costs, which is a seventeen-percent (17%) decrease, CGT-Redwood was $9,281,483, a eleven-percent (11%) increase, EPNG-Basin of $1,502,996, a twenty-six percent (26%) decrease, NGTL-AECO/NIT of $154,548, a seventy-three percent (73%) decrease, GTNC-All of $2,389,061, a nine percent (9%) decrease, and Transwestern-Basin of $629,796, a four percent (4%) percent decrease. These costs are included in the CPIM and are part of the PGA balancing account.

TABLE 3-11 Pacific Gas and Electric Company Commodity Volumetric Transport Costs CPIM Year 17 November 1, 2009 through October 31, 2010	
CGT-Baja	$ 9,945,458
CGT-Redwood	9,281,483
EPNG-Basin	1,502,996
NGTL-AECO/NT	154,548
GTNC-ALL	2,389,061
TW-Basin	629,796
Total Volumetric Transport Costs:	$ 23,903,342

3.14 Review of Benchmark Commodity Indices

Table 3-12 provides a summary of PG&E's CityGate indices used to calculate the benchmark of monthly commodity costs. These indices are reported to *Natural Gas Intelligence*, which publishes them in their gas price index. As such, these indices were applied to the CityGate benchmark volume reported at 266,731,852 MMBtus (shown in Table 3-2) to determine the commodity benchmark costs of $1,210,315,414. DRA compilations show the commodity benchmark cost, plus the benchmark demand charges of $270,472,329 resulted in the total market benchmark costs for Year 17 of $1,480,787,743.

The Canadian benchmark commodity indices are established using the exchange rates in effect when the indices are issued prior to the availability of closing currency exchange rates. However, the final indices, which determine the actual gas supply prices, reflect closing exchange rates.

For the reporting period, PG&E's gas operations apply a pipeline sequencing methodology for purposes of purchasing gas at the lowest cost. Management however has the discretion to change the sequence to select a pipeline at any time in order to meet reliability requirements.

TABLE 3-12 Pacific Gas and Electric Company PG&E City Gate Indices CPIM Year 17 November 1, 2009 through October 31, 2010					
Month Year	California Topock (Firm)	Kingsgate	San Juan	AECO	(End of Month) PG&E CityGate NGI Daily Index
Nov-09	$4.673578	$5.120413	$4.531582	$4.878710	$4.32
Dec-09	4.785140	5.054918	4.552376	4.810845	6.34
Jan-10	6.082415	5.685050	6.048601	5.388195	5.62
Feb-10	5.626025	5.821211	5.632733	5.521375	5.14
Mar-10	4.976938	5.565752	4.925757	5.257652	4.36
Apr-10	4.165579	4.553139	4.021243	4.239997	4.53
May-10	4.185863	4.030000	4.052433	3.731513	4.30
Jun-10	3.993165	4.128230	3.938070	3.827431	4.53
Jul-10	4.682820	4.567825	4.551476	4.256178	4.45
Aug-10	4.408987	4.057719	4.333144	3.752066	3.56
Sep-10	3.577344	3.779582	3.449424	3.465523	4.11
Oct-10	3.922171	3.986932	3.802913	3.675939	3.93

3.15 Examination of Fixed Storage and Transportation Costs

Pursuant to Advice Letter 2856-G, PG&E reported its benchmark reservation (demand) and fixed storage charges. Based on this report, DRA reviewed the costs and identified changes in activity from prior year report. The total transportation and storage costs of $270,472,332, is a six-percent (6%) increase from prior year. The Canadian pipeline transactions of $58,141,166 showed a thirty-five percent (35%) increase. U.S. interstate was $111,005,038, had a less than one-percent (1%) change, similarly for California intrastate showed $58,783,965, also had a less than one-percent (1%) change, and intrastate fixed and incremental storage costs were $42,403,517, a nominal one-percent (1%) change from prior year. Table 3-13 provides a summary of these costs.

TABLE 3-13
Pacifc Gas and Electric Company
Summary of Fixed Transport and Storage Costs
CPIM Year 17
November 1, 2009 through October 31, 2010

Canadian Pipelines:	**$**
Foothills Pipeline	16,484,007
Nova Gas Transmission Ltd.	41,657,159
Total Canadian Pipeline Costs:	$58,141,166
U.S. Interstate Pipelines:	
Gas Transmission Northwest Corp.	71,289,011
El Paso Natural Gas	19,944,319
Kern River Gas	(8,392)
Transwestern Pipeline Company	19,918,746
Total U.S. Interstate Pipeline Costs:	$111,143,684
CA Intrastate Pipelines:	
CGT- Baja	36,440,226
CGT-Redwood	22,306,669
CGT-Silverado	37,070
Total CA Intrastate Pipeline Costs:	$58,783,965
CA Intrastate Storage Contract Costs:	
CGT Firm Contracts	40,694,513
CGT Incremental Contracts	800,004
Lodi Contracts	909,000
Total CA Intrastate Storage Costs:	$42,403,517
Total Transportation & Storage Costs:	$270,472,332

3.16 Utilization of Firm Interstate and Intrastate Pipeline Assets

PG&E has short and long term contracts for purchases of natural gas resources transported from Canadian, U.S. interstate and California intrastate pipeline systems to meet core gas demand. During Year 17, PG&E transported these resources using firm transportation contracts. A summary in Table 3-14 below shows PG&E's estimated utilization for the period and noted changes in contract activity from prior year. PG&E estimates utilization proportionally based on capacity available to transport supplies and/or releases to other parties.

Pursuant to D.04-09-022, [20] PG&E is authorized to recover the costs associated with its Canadian and U.S. interstate capacity, allocate firm intrastate capacity and recover associated costs. Commission D.07-07-002 authorized PG&E to change Baja Path quantities to a combined annual and winter (December through February) core capacity supply of 669 MDth per day as shown in Table 3-14 and PG&E's CPIM Performance Report. [21]

[20] D.04-09-022, OIR to establish Policies and Rules to Ensure Reliable; Long term Supplies of Natural Gas to California.

[21] PG&E Table III, Page 14, PG&E Annual Performance Report, CPIM Year-17, Application 96-08-043, dated March 16, 2011

TABLE 3-14
Pacific Gas and Electric Company
Core Gas Supply - Utilization of Interstate, Intrastate and Canadian Pipeline Assets
CPIM Year 17
November 1, 2009 through October 31, 2010

Pipeline Capacity:	Quantity (Dth/d)	Contract Expiration Date	Utilization Rate	Change from Prior Year Capacity
TransCanada Pipelines:				
NOVA	249,401	10/31/11		
	287,745	10/31/11		
	82,223			
Total NOVA:	619,369		100%	0%
Foothills-BC System	244,860	10/31/11		
	284,810	10/31/12		
	81,384	10/31/12		
Total Foothills-BC System:	611,054		100%	0%
Interstate Pipelines:				
Gas Transmission Northwest	250,000	10/31/11		
	279,968	10/31/16		
	80,000	10/31/20		
Total Gas Transmission Northwest:	609,968		98%	2%
El Paso Natural Gas	116,035	06/30/12		
	85,739	06/30/13		
Total El Paso Natural Gas:	201,774		89%	9%
Transwestern Pipeline Co.	150,000	03/31/13		
	76,720	02/28/10		
	26,720	02/28/11		
	43,220	02/29/12		
Total Transwestern Pipeline Co:	296,660		98%	1%
Intrastate Pipelines:				
Silverado Path	1,000	No expiration	100%	0%
Redwood Path	608,766	No expiration	100%	0%
Baja Path	348,000	No expiration		
	321,000	No expiration		
Total Baja Pipelines:	669,000		86%	11%

APPENDIX A-1

EXHIBITS FOR CPIM YEAR 16 REPORT

Section	Description	Exhibit Number
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EXHIBITS FOR CPIM YEAR 17 REPORT

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Pacific Gas and Electric
Benchmark Commodity Costs and Reservation Charges
CPIM Year 16
November 1, 2008 through October 31, 2009

Benchmark by Pipeline	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Total Commodity Benchmark**
California Firm	$ 115,770	$ 170,841	$ 167,028	$ 105,476	$ 104,842	$ 103,290	$ 92,287	$ 96,000	$ 105,803	$ 107,663	$ 82,920	$ 118,048	$ 1,369,968
Kingsgate	1,740,780	1,841,896	2,092,438	1,585,220	1,109,490	955,200	358,391	536,370	475,912	1,226,887	1,197,660	1,429,193	14,549,437
San Juan	29,709,328	65,781,349	73,890,515	40,790,568	29,197,086	27,191,280	26,872,350	29,296,560	34,414,898	27,821,601	14,399,640	13,090,906	412,456,081
AECO	44,910,179	96,015,182	58,238,808	56,720,215	49,128,452	49,786,085	29,316,599	19,537,248	14,448,252	21,286,754	24,129,935	45,941,198	509,458,907
Topock Firm	-	16,400,963	5,176,104	6,325,896	-	-	-	-	-	-	-	-	27,902,963
CityGate As Available	-	11,588,964	2,425,577	2,046,964	5,658,158	3,365,599	-	-	-	-	-	-	25,085,262
CPIM Market Benchmark :	$ 76,476,057	$ 191,799,195	$ 141,990,470	$ 107,574,339	$ 85,198,028	$ 81,401,454	$ 56,639,627	$ 49,466,178	$ 49,444,865	$ 50,442,905	$ 39,810,155	$ 60,579,345	$ 990,822,618
Benchmark Reservation Charges													
Trans-Canada BC System	$ 892,198	$ 916,091	$ 836,318	$ 814,299	$ 821,066	$ 845,293	$ 918,629	$ 883,689	$ 944,063	$ 936,518	$ 943,143	$ 952,649	10,703,956
California Gas Transmission	7,857,936	10,419,613	10,342,854	10,336,043	7,728,935	7,630,824	7,628,771	7,775,102	7,818,154	7,808,212	7,809,586	7,765,081	100,921,111
El Paso Natural Gas Company	1,764,427	2,239,637	2,558,720	2,167,145	1,200,984	1,862,236	1,770,813	1,727,225	1,697,935	1,771,387	1,771,388	1,771,387	22,303,284
Lodi Gas Storage, Inc.	85,000	85,500	85,000	86,500	88,000	75,750	75,775	75,750	75,775	75,775	75,750	75,425	960,000
Nova Gas Transmission. Ltd.	2,323,733	2,385,962	2,603,580	2,535,031	2,556,099	2,631,522	2,859,827	2,751,052	2,939,005	2,915,518	2,936,140	2,965,737	32,403,206
Gas Transmission Northwest Corp.	5,859,371	6,054,683	6,054,683	5,468,746	6,054,683	5,859,371	6,054,683	5,859,371	6,054,683	6,054,683	5,859,371	6,054,683	71,289,011
Transwestern Pipeline Company	1,349,813	1,735,287	1,735,287	1,567,356	1,395,000	1,350,000	1,395,000	1,350,000	1,395,000	1,395,000	1,350,000	1,395,000	17,412,743
Total Benchmark Reservation Charges:	20,132,478	23,836,773	24,216,442	22,975,120	19,844,767	20,254,996	20,703,498	20,422,189	20,924,615	20,957,093	20,745,378	20,979,962	255,993,311
													-
Total Benchmark Costs:	$ 96,608,535	$ 215,635,968	$ 166,206,912	$ 130,549,459	$ 105,042,795	$ 101,656,450	$ 77,343,125	$ 69,888,367	$ 70,369,480	$ 71,399,998	$ 60,555,533	$ 81,559,307	$ 1,246,815,929

Exhibit 2-1A

Pacific Gas and Electric
Benchmark Sequenced Gas Volume
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/ Year	California Firm	Kingsgate	San Juan	AECO	Topock Firm	CityGate as Available	Total Commodity Benchmark at CityGate
Nov-08	$ 30,000.00	$ 289,200.00	$ 9,731,377.00	$ 7,711,537.00	$ -	$ -	$ 17,762,114.00
Dec-08	31,000.00	287,401.00	13,391,783.00	15,465,195.00	2,976,168.00	1,810,543.00	33,962,090.00
Jan-09	31,000.00	356,097.00	14,434,871.00	10,278,356.00	960,622.00	421,138.00	26,482,084.00
Feb-09	28,000.00	321,636.00	12,240,340.00	12,005,113.00	1,679,198.00	430,365.00	26,704,652.00
Mar-09	31,000.00	264,492.00	10,080,998.00	12,312,263.00	-	1,370,549.00	24,059,302.00
Apr-09	30,000.00	255,960.00	9,630,180.00	14,141,026.00	-	958,102.00	25,015,268.00
May-09	31,000.00	104,191.00	9,956,735.00	9,125,156.00	-	-	19,217,082.00
Jun-09	30,000.00	156,240.00	10,262,550.00	6,079,281.00	-	-	16,528,071.00
Jul-09	31,000.00	138,539.00	10,763,231.00	4,512,505.00	-	-	15,445,275.00
Aug-09	31,000.00	379,006.00	8,170,391.00	7,092,760.00	-	-	15,673,157.00
Sep-09	30,000.00	411,090.00	5,397,660.00	9,019,225.00	-	-	14,857,975.00
Oct-09	31,000.00	436,263.00	3,581,996.00	15,136,703.00	-	-	19,185,962.00
Totals:	$ 365,000.00	$ 3,400,115.00	$ 117,642,112.00	$ 122,879,120.00	$ 5,615,988.00	$ 4,990,697.00	$ 254,893,032.00

Exhibit 2-1B

Pacific Gas and Electric
Total Commodity Benchmark
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/ Year	California Firm	Kingsgate	San Juan	AECO	Topock Firm	CityGate as Available	Total Commodity Benchmark
Nov-08	$ 115,770	$ 1,740,780	$ 29,709,328	$ 44,910,179	$ -	$ -	$ 76,476,057
Dec-08	170,841	1,841,896	65,781,349	96,015,182	16,400,963	11,588,964	191,799,195
Jan-09	167,028	2,092,438	73,890,515	58,238,808	5,176,104	2,425,577	141,990,470
Feb-09	105,476	1,585,220	40,790,568	56,720,215	6,325,896	2,046,964	107,574,339
Mar-09	104,842	1,109,490	29,197,086	49,128,452	0	5,658,158	85,198,028
Apr-09	103,290	955,200	27,191,280	49,786,085	0	3,365,599	81,401,454
May-09	92,287	358,391	26,872,350	29,316,599	0	0	56,639,627
Jun-09	96,000	536,370	29,296,560	19,537,248	0	0	49,466,178
Jul-09	105,803	475,912	34,414,898	14,448,252	0	0	49,444,865
Aug-09	107,663	1,226,887	27,821,601	21,286,754	0	0	50,442,905
Sep-09	82,920	1,197,660	14,399,640	24,129,935	0	0	39,810,155
Oct-09	118,048	1,429,193	13,090,906	45,941,198	0	0	60,579,345
Totals:	$ 1,369,968	$ 14,549,437	$ 412,456,081	$ 509,458,907	$ 27,902,963	$ 25,085,262	$ 990,822,618

Exhibit 2-1C

Pacific Gas and Electric
Actual Commodity Costs by Pipeline
CPIM Year 16
November 1, 2008 through October 31, 2009

Gas Purchases by Pipeline:	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Total Commodity Costs:**
CGT Baja	$ 890,972	$ 1,679,076	$ 1,799,631	$ 1,330,675	$ 900,165	$ 853,952	$ 867,915	$ 868,805	$ 889,747	$ 739,391	$ 635,941	$ 472,899	$ 11,929,169
CGT-City-Gate	(38,144,876)	(10,606,121)	(44,761,776)	(19,168,845)	(3,206,785)	(6,104,649)	(23,958,125)	(16,177,526)	(17,798,814)	(10,383,413)	(7,119,260)	(15,526,285)	(212,956,475)
CGT-Redwood	777,737	874,031	811,536	724,498	768,479	848,821	747,816	553,458	485,445	481,022	516,053	758,009	8,346,905
EPNG-Basin	17,927,452	37,647,990	40,328,112	23,852,447	15,388,743	15,580,965	16,028,661	16,466,493	18,347,695	16,467,228	11,966,638	10,533,339	240,535,763
EPNG-Topock	(931,801)	17,667,467	17,968,001	5,720,926	-	(798,577)	-	-	-	346,102	(444,917)	(820,667)	38,706,534
Kern River Daggett	-	-	107,237	197,987	-	-	-	36,855	-	334	-	-	342,413
NGTL-AECO-NIT	98,868,597	111,862,568	101,913,588	76,638,726	59,428,089	60,266,572	53,947,575	38,849,229	38,042,972	37,013,113	32,559,458	53,496,474	762,886,961
GTNC-All	(1,521,404)	(4,032,040)	(3,553,827)	(3,549,028)	(2,670,999)	(1,510,723)	(3,089,995)	(2,173,560)	(6,749,485)	(6,737,306)	(5,540,370)	(828,045)	(41,956,782)
TW-Basin	12,863,296	25,714,089	30,358,630	16,019,929	12,584,776	11,464,032	11,949,286	11,539,171	13,552,556	10,196,057	7,295,830	9,569,723	173,107,375
TW-Topock	-	2,856,223	3,714,899	113,671	304,544	-	(2,067,824)	(892,177)	(489,365)	520,839	-	-	4,060,810
Adjustments for Related Costs:													
Hedging Costs	-	-	-	-	(34,100)	-	-	-	-	-	-	-	(34,100)
Miscellaneous Costs & Revenues	238,829	(102,358)	(556,704)	(543,065)	(528,198)	(843,617)	(915,181)	(688,446)	(514,629)	(626,835)	(633,153)	(975,832)	(6,689,189)
Total Commodity Costs:	$ 90,968,802	$ 183,560,925	$ 148,129,327	$ 101,337,921	$ 82,934,714	$ 79,756,776	$ 53,510,128	$ 48,382,302	$ 45,766,122	$ 48,016,532	$ 39,236,220	$ 56,679,615	$ 978,279,384

Pacific Gas and Electric
Summary of Actual Commodity Costs and Reservation Charges
CPIM Year 16
November 1. 2008 through October 31, 2009

Actual Commodity Costs - by Pipeline	**Actual Costs**
CGT - Baja	$11,929,169
CGT - CityGate	(212,956,475)
CGT - Redwood	8,346,905
EPNG - Basin	240,535,763
EPNG - Topock	38,706,534
Kern River - Daggett	342,413
NGTL - AECO-NIT	762,886,961
GTNC-All	(41,956,782)
TW-Basin	173,107,375
Hedging Derivative Adjustments	(34,100)
TW-Topock	4,060,810
Miscellaneous Costs & Revenues	(6,689,189)
Total Commodity Costs:	$ 978,279,384.00

Actual Commodity Sales - by Pipeline	
CGT - City-Gate	$ (235,900,028.00)
EPNG - Basin	(4,275,962.00)
EPNG - Topock	(2,513,255.00)
NGTL - AECO-NIT	(8,850,133.00)
GTNC-All	(46,607,920.00)
TW Basin	(1,288,717.00)
TW Topock	(3,485,166.00)
Total Commodity Sales:	$ (302,921,181.00)

Actual Reservation Charges:	
Trans-Canada B.C. System	$ 10,401,630.00
California Gas Transmission	86,526,589.00
El Paso Natural Gas Company	21,225,852.00
Lodi Gas Storage, Inc.	960,000.00
Nova Gas Transmission, Ltd.	29,573,213.00
Gas Transmission Northwest corp.	69,957,604.00
Transwestern Pipeline Company	16,866,528.00
Total Reservation Charges:	$ 235,511,416.00
Net Actual Costs:	$ 910,869,619.00

Total Volume in MMBtus: 266,931,696

Exhibit 2-2B

SB_GT&S_0434592

Pacific Gas and Electric
Summary of Actual Commodity Costs and Capacity Reservation Charges
CPIM Year 16
November 1, 2008 through October 31, 2009

Actual Net Commodity Costs:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	YTD Total
Baja Path	$ 31,681,720	$ 85,621,145	$ 94,488,359	$ 47,394,226	$ 29,178,227	$ 29,116,490	$ 29,810,499	$ 29,273,536	$ 33,810,835	$ 28,269,951	$ 19,973,600	$ 20,575,961	$ 479,194,549
Mission Path	-	12,053,165	389,111	1,360,434	6,609,514	2,245,775	-	39,825	193,588	52,142	-	-	22,943,554
Redwood Path	100,076,853	118,329,911	104,662,203	78,664,080	60,442,353	61,433,653	54,892,954	41,957,516	39,382,761	37,642,812	33,217,807	55,082,847	785,785,750
Commodity Sales	(41,028,600)	(32,340,938)	(50,853,643)	(25,537,755)	(12,733,082)	(12,195,525)	(30,278,144)	(22,200,129)	(27,106,431)	(17,321,538)	(13,322,036)	(18,003,361)	(302,921,182)
Hedging Costs Adjustment	-	-	-	-	(34,100)	-	-				-	-	(34,100)
Miscellaneous Costs & Revenues	238,829	(102,358)	(556,704)	(543,065)	(528,198)	(843,617)	(915,181)	(688,446)	(514,629)	(626,835)	(633,153)	(975,832)	(6,689,189)
Total Net Commodity Costs:	$ 90,968,802	$ 183,560,925	$ 148,129,326	$ 101,337,920	$ 82,934,714	$ 79,756,776	$ 53,510,128	$ 48,382,302	$ 45,766,124	$ 48,016,532	$ 39,236,218	$ 56,679,615	$ 978,279,382
Actual Demand Charges													
TransCanada-B.C. System	$ 892,198	$ 916,091	$ 836,318	$ 814,299	$ 787,766	$ 845,293	$ 900,801	$ 816,634	$ 886,511	$ 879,426	$ 883,956	$ 942,337	$ 10,401,630
California Gas Transmission	7,854,936	8,169,013	10,339,753	7,037,643	7,005,085	7,627,824	7,228,097	6,463,352	6,295,280	6,196,988	6,025,336	6,283,281	86,526,588
El Paso Natural Gas Company	1,756,708	2,220,810	2,522,000	2,143,229	976,536	1,830,286	1,734,845	1,695,275	1,661,967	1,605,219	1,637,438	1,441,539	21,225,852
Lodi Gas Storage, Inc	85,000	85,500	85,000	86,500	88,000	75,750	75,775	75,750	75,775	75,775	75,750	75,425	960,000
NOVA Gas Transmission Ltd.	2,323,733	2,385,962	2,598,670	2,535,031	2,270,417	2,622,427	2,703,862	2,265,954	2,331,153	2,312,523	2,348,470	2,875,011	29,573,213
Gas Transmission Northwest Corp.	5,859,371	6,054,683	6,054,683	5,468,746	5,959,906	5,829,370	5,958,581	5,709,367	5,758,188	5,758,188	5,572,440	5,974,081	69,957,604
Transwestern Pipeline Company	1,334,985	1,719,965	1,884,812	1,553,517	1,379,678	1,335,173	1,379,678	1,335,173	1,379,678	1,198,328	1,156,673	1,208,868	16,866,528
Total Demand charges:	$ 20,106,931	$ 21,552,024	$ 24,321,236	$ 19,638,965	$ 18,467,388	$ 20,166,123	$ 19,981,639	$ 18,361,505	$ 18,388,552	$ 18,026,447	$ 17,700,063	$ 18,800,542	$ 235,511,415
Total Gas Costs:	$ 111,075,733	$ 205,112,949	$ 172,450,562	$ 120,976,885	$ 101,402,102	$ 99,922,899	$ 73,491,767	$ 66,743,807	$ 64,154,676	$ 66,042,979	$ 56,936,281	$ 75,480,157	$ 1,213,790,797

Exhibit 2-2C

Pacific Gas And Electric Company
Net Purchases by Volume (MMBtus)
CPIM Year 16
November 1, 2008 through October 31, 2009

Pipeline/Purchase Point:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Volume:
CGT City gate	(6,249,699)	(1,736,621)	(8,742,267)	(4,258,551)	(813,355)	(1,846,875)	(6,468,738)	(5,038,578)	(5,175,769)	(2,995,656)	(2,134,777)	(3,125,012)	(48,585,898)
EPNG-Basin	6,029,507	7,993,912	8,306,780	7,586,317	5,729,755	5,878,706	6,319,511	6,119,626	6,061,964	5,141,606	4,651,968	2,954,859	72,774,511
EPNG-Topock	(251,838)	3,291,709	3,554,803	1,563,988		(247,632)				120,933	(169,170)	(217,529)	7,645,264
Kern River Daggett			27,273	53,460				11,700		126			92,559
NGTL-AECO/NIT	17,749,495	19,124,329	19,108,852	17,344,319	16,109,869	18,317,462	17,431,925	13,042,280	13,142,403	13,415,053	12,886,248	17,271,838	194,944,073
GTNC-All	(294,300)	(708,400)	(713,347)	(869,194)	(810,200)	(550,758)	(1,080,400)	(672,640)	(2,235,865)	(2,315,056)	(1,995,600)	(289,200)	(12,534,960)
TW Basin	4,494,432	5,503,236	6,293,951	5,109,164	4,640,506	4,328,514	4,485,736	4,274,384	4,445,138	3,168,582	2,920,580	2,778,162	52,442,385
TW Topock		534,297	713,584	28,909	99,200		666,032	(290,129)	(153,500)	157,433	-		1,755,826
Net Purchase Volume	21,477,597	34,002,462	28,549,629	26,558,412	24,955,775	25,879,417	21,354,066	17,446,643	16,084,371	16,693,021	16,159,249	19,373,118	268,533,760

Exhibit 2-3A

Pacific Gas and Electric
Core Supply Portfolio Composition
CPIM Year 16
November
November 1, 2008 through October 31, 2009

	Volume (MMBtus)(1)				Average Price - U.S Dollars $				Percentage of Total			Total
Month/Year	**SW**	**BL**	**MM**	**Total**	**SW**	**BL**	**MM**	**Total**	**SW**	**BL**	**MM**	**Percent**
Nov-08	3,582,968	5,646,914	19,087,910	28,317,792	5.48	3.80	4.64	4.64	12.7%	19.9%	67.4%	100.0%
Dec-08	3,860,494	5,383,954	30,017,976	39,262,424	5.85	5.44	5.36	5.55	9.8%	13.7%	76.5%	100.0%
Jan-09	2,032,359	6,857,192	29,527,370	38,416,921	4.87	5.08	5.14	5.03	5.3%	17.8%	76.9%	100.0%
Feb-09	3,516,102	2,319,186	26,451,109	32,286,397	3.84	3.80	3.88	3.84	10.9%	7.2%	81.9%	100.0%
Mar-09	6,641,736	2,720,137	18,869,517	28,231,390	3.44	2.70	3.39	3.18	23.5%	9.6%	66.8%	100.0%
Apr-09	2,725,067	4,950,378	21,965,174	29,640,619	3.06	3.09	3.05	3.07	9.2%	16.7%	74.1%	100.0%
May-09	6,501,621	3,964,919	18,153,659	28,620,199	3.17	2.75	2.82	2.91	22.7%	13.9%	63.4%	100.0%
Jun-09	5,533,264	4,008,854	14,925,672	24,467,790	2.83	2.80	2.85	2.83	22.6%	16.4%	61.0%	100.0%
Jul-09	7,435,048	3,190,611	13,674,171	24,299,830	2.78	2.96	3.02	2.92	30.6%	13.1%	56.3%	100.0%
Aug-09	4,257,071	4,381,392	13,380,184	22,018,647	2.64	2.85	3.03	2.84	19.3%	19.9%	60.8%	100.0%
Sep-09	3,286,388	4,177,546	13,019,196	20,483,130	2.74	2.43	2.49	2.55	16.0%	20.4%	63.6%	100.0%
Oct-09	4,534,814	4,235,481	14,379,697	23,149,992	3.98	3.01	3.01	3.33	19.6%	18.3%	62.1%	100.0%
Totals	53,906,932	51,836,564	233,451,635	339,195,131					15.9%	15.3%	68.8%	100.0%

(1) MMBtu purchases are volumes at point of purchase.
SW = Swing, or daily spot, less than one month duration.
BL= Baseload is a one month duration, purchased for prompt (next) month.
MM= Multi-month is a purchase that is further out than prompt month.

Exhibit 2-3B

Pacific Gas and Electric
Actual Commodity Sales
CPIM Year 16
November 1, 2008 through October 31, 2009

Commodity Sales:	**Nov-08**	**Dec-08**	**Jan-09**	**Feb-09**	**Mar-09**	**Apr-09**	**May-09**	**Jun-09**	**Jul-09**	**Aug-09**	**Sep-09**	**Oct-09**	**Total Sales:**
CGT City-Gate	$38,144,876	$22,659,286	$45,150,887	$20,529,280	$9,816,298	$8,350,424	$23,958,125	$16,217,351	$17,992,401	$10,435,555	$7,119,260	$15,526,285	$235,900,028
EPNG-Basin	931,801	56,300	211,849	158,590	0	768,447	928,837	277,250	867,696	0	75,192	0	4,275,962
EPNG-Topock	0	0	0	0	0	1,247,671	0	0	0	0	444,917	820,667	2,513,255
NGTL-AECO/NIT	232,426	5,379,965	1,725,906	1,098,484	65,115	113,674	0	177,171	57,392	0	0	0	8,850,133
GTNC-All	1,719,497	4,245,387	3,765,001	3,751,401	2,851,669	1,715,309	3,287,558	4,551,218	7,546,437	6,885,982	5,682,667	605,794	46,607,920
TW Basin	0	0	0	0	0	0	0	84,962	153,140	0	0	1,050,615	1,288,717
TW Topock	0	0	0	0	0	0	2,103,624	892,177	489,365	0	0	0	3,485,166
Total Commodity Sales:	$41,028,600	$32,340,938	$50,853,643	$25,537,755	$12,733,082	$12,195,525	$30,278,144	$22,200,129	$27,106,431	$17,321,537	$13,322,036	$18,003,361	$302,921,181
Commodity Volume:													
CGT City-Gate	$6,249,699	$3,636,397	$8,806,365	$4,548,537	$2,445,700	$2,491,770	$6,468,738	$5,053,578	$5,235,769	$3,010,571	$2,134,777	$3,125,012	$53,206,913
EPNG-Basin						280,147	373,027	90,723	282,596		24,334		1,050,827
EPNG-Topock	251,838	10,000	45,226	42,065		401,563					169,170	217,529	1,137,391
NGTL-AECO/NIT	44,358	905,165	302,354	265,389	19,715	36,965		64,452	19,430			137,433	1,795,261
GTNC-All	294,300	708,400	713,347	871,994	810,200	550,758	1,080,400	1,495,039	2,474,865	2,315,056	1,995,600	296,900	13,606,859
TW Basin								27,223	49,300				76,523
TW Topock							676,032	290,129	153,500				1,119,661
Total Volume Sales:	$6,840,195	$5,259,962	$9,867,292	$5,727,985	$3,275,615	$3,761,203	$8,598,197	$7,021,144	$8,215,460	$5,325,627	$4,323,881	$3,776,874	$71,993,435

Exhibit 2-4A

Pacific Gas and Electric
Actual Sales by Volume (MMBtus)
CPIM Year 16
November 1, 2008 through October 31, 2009

Sales by Pipeline:	**Volume (MMBtus)**	**$**
CGT-CityGate	53,206,913	235,900,028
EPNG-Basin	1,050,827	4,275,962
EPNG-Topock	1,137,391	2,513,255
NGTL-AECO/NIT	1,795,261	8,850,133
GTNC-All	13,606,859	46,607,920
TW Basin	76,523	1,288,717
TW Topock	1,119,661	3,845,166
Total Volume:	71,993,435	$ 303,281,181

Exhibit 2-4B

Pacific Gas and Electric
Commodity Volumetric Transport Costs
CPIM Year 16
November 1, 2008 through October 31, 2009

Transport Costs by Pipeline:	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Total Volumetric Costs
CGT-Baja	$ 890,972	$ 1,679,076	$ 1,799,631	$ 1,330,675	$ 900,165	$ 853,952	$ 867,915	$ 868,805	$ 889,747	$ 739,391	$ 635,941	$ 472,899	$ 11,929,169
CGT City gate	-	-	-	-	-	-	-	-	-	-	-	-	-
CGT-Redwood	777,737	874,031	811,536	724,498	768,479	848,821	747,816	553,458	485,445	481,022	516,053	758,009	8,346,905
EPNG-Basin	218,153	286,596	238,545	215,771	23,517	166,530	178,890	173,665	172,305	146,096	132,197	84,286	2,036,551
NGTL-AECO/NIT	-	697	-	5,094	12,890	-	-	-	159,558	200,122	184,518	-	562,879
GTNC-All	198,093	213,347	211,174	191,733	180,670	204,586	197,563	150,589	151,680	148,677	142,296	194,157	2,184,565
TW Basin	56,119	68,716	77,327	63,703	57,943	54,048	56,011	53,469	55,504	39,652	36,468	35,231	654,191
Total Transport Cost:	$ 2,141,074	$ 3,122,463	$ 3,138,213	$ 2,531,474	$ 1,943,664	$ 2,127,937	$ 2,048,195	$ 1,799,986	$ 1,914,239	$ 1,754,960	$ 1,647,473	$ 1,544,582	$ 25,714,260

Source: Actual Cost Detail - Volumetric Transportation Costs

Pacific Gas and Electric Company
Reconciliation of Reservation Charges and Capacity Release
CPIM Year 16
November 1, 2008 through October 31, 2009

Pipeline:	Reservation Charges	Capacity Release Revenue	Discounted (Premium) Capacity Release	Reservation Charge Discount	Refund Adjustments	Other Cost Adjustments (1)	TOTAL
Canadian Pipelines:							
TransCanada	$10,703,956	($1,061,491)	$759,165	$0	$0	$0	$10,401,630
NOVA	32,403,206	(4,821,376)	1,991,384	-	-		29,573,214
Sub-Total:							39,974,844
Interstate Pipelines:							
El Paso	22,646,609	(714,560)	-	(362,872)	-	(343,325)	21,225,852
Lodi	950,000	-	-	-	-	10,000	960,000
GTN	71,289,011	(1,331,406)	-	-	-		69,957,605
Transwestern	17,583,243	(530,660)	-	(186,058)	-		16,866,525
Sub-Total:							109,009,982
Intrastate Pipelines:							
CGT	58,980,963	(7,526,228)	(6,868,297)	-	-		44,586,438
Firm Core Storage	41,119,314	-	-				41,119,314
Incremental Core Storage	820,834	-	-				820,834
Sub-Total:							86,526,586
Total:	$256,497,136	($15,985,721)	($4,117,748)	($548,930)	$0	($333,325)	$235,511,412

(1) Other Cost Adjustments = Injection/Withdrawal Charges

Exhibit 2-6A

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 16
November 1, 2008 through October 31, 2009

El Paso Natural Gas Co.

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	201,774	30	6,053,220	(150,180)	5,903,040	5,864,314	99.34%
Dec-08	266,774	31	8,269,994	(161,045)	8,108,949	7,704,188	95.01%
Jan-09	266,774	31	8,269,994	0	8,269,994	8,169,363	98.78%
Feb-09	266,774	28	7,469,672	(61,768)	7,407,904	7,389,422	99.75%
Mar-09	201,774	31	6,254,994	(653,759)	5,601,235	5,575,621	99.54%
Apr-09	201,774	30	6,053,220	(300,360)	5,752,860	5,703,069	99.13%
May-09	201,774	31	6,254,994	0	6,254,994	6,126,356	97.94%
Jun-09	201,774	30	6,053,220	0	6,053,220	5,947,444	98.25%
Jul-09	201,774	31	6,254,994	0	6,254,994	5,900,852	94.34%
Aug-09	201,774	31	6,254,994	(1,240,000)	5,014,994	5,003,295	99.77%
Sep-09	201,774	30	6,053,220	(1,500,000)	4,553,220	4,527,304	99.43%
Oct-09	201,774	31	6,254,994	(3,348,000)	2,906,994	2,866,863	98.62%
Totals:			79,497,510	(7,415,112)	72,082,398	70,778,091	98.19%

Transwestern Pipeline Company

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	150,000	30	4,500,000	(113,310)	4,386,690	4,384,332	99.95%
Dec-08	180,000	31	5,580,000	(120,776)	5,459,224	5,368,411	98.34%
Jan-09	205,000	31	6,355,000	0	6,355,000	6,041,203	95.06%
Feb-09	180,000	28	5,040,000	(46,340)	4,993,660	4,976,777	99.66%
Mar-09	150,000	31	4,650,000	(118,203)	4,531,797	4,526,808	99.89%
Apr-09	150,000	30	4,500,000	(89,880)	4,410,120	4,222,467	95.74%
May-09	150,000	31	4,650,000	0	4,650,000	4,375,839	94.10%
Jun-09	150,000	30	4,500,000	0	4,500,000	4,177,235	92.83%
Jul-09	150,000	31	4,650,000	0	4,650,000	4,336,231	93.25%
Aug-09	150,000	31	4,650,000	(1,550,000)	3,100,000	3,097,786	99.93%
Sep-09	150,000	30	4,500,000	(1,650,000)	2,850,000	2,849,025	99.97%
Oct-09	150,000	31	4,650,000	(1,922,000)	2,728,000	2,710,097	99.34%
Totals:			58,225,000	(5,610,509)	52,614,491	51,066,210	97.06%

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 16
November 1, 2008 through October 31, 2009

Gas Transmission Northwest Corporation

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	609,968	30	18,299,040	0	18,299,040	17,218,964	94.10%
Dec-08	609,968	31	18,909,008	0	18,909,008	18,462,319	97.64%
Jan-09	609,968	31	18,909,008	0	18,909,008	18,170,747	96.10%
Feb-09	609,968	28	17,079,104	0	17,079,104	16,458,066	96.36%
Mar-09	609,968	31	18,909,008	(1,864,092)	17,044,916	15,653,649	91.84%
Apr-09	609,968	30	18,299,040	(300,000)	17,999,040	17,756,817	98.65%
May-09	609,968	31	18,909,008	(1,550,000)	17,359,008	17,180,371	98.97%
Jun-09	609,968	30	18,299,040	(2,850,000)	15,449,040	13,513,574	87.47%
Jul-09	609,968	31	18,909,008	(5,662,367)	13,246,641	13,190,325	99.57%
Aug-09	609,968	31	18,909,008	(5,662,367)	13,246,641	12,932,904	97.63%
Sep-09	609,968	30	18,299,040	(5,479,710)	12,819,330	12,440,159	97.04%
Oct-09	609,968	31	18,909,008	(1,240,000)	17,669,008	16,615,106	94.04%
Totals:			222,638,320	(24,608,536)	198,029,784	189,593,001	95.74%

California Gas Transmission-Baja Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	348,000	30	10,440,000	(532,560)	9,907,440	9,866,802	99.59%
Dec-08	669,000	31	20,739,000	(3,522,654)	17,216,346	16,678,785	96.88%
Jan-09	669,000	31	20,739,000	(1,255,779)	19,483,221	18,278,782	93.82%
Feb-09	669,000	28	18,732,000	(4,618,908)	14,113,092	13,830,302	98.00%
Mar-09	348,000	31	10,788,000	(689,967)	10,098,033	10,068,955	99.71%
Apr-09	348,000	30	10,440,000	(809,820)	9,630,180	9,552,038	99.19%
May-09	348,000	31	10,788,000	(831,265)	9,956,735	9,708,223	97.50%
Jun-09	348,000	30	10,440,000	(177,450)	10,262,550	9,718,175	94.70%
Jul-09	348,000	31	10,788,000	(19,654)	10,768,346	9,952,431	92.42%
Aug-09	348,000	31	10,788,000	(2,501,235)	8,286,765	8,270,591	99.80%
Sep-09	348,000	30	10,440,000	(3,300,000)	7,140,000	7,113,430	99.63%
Oct-09	348,000	31	10,788,000	(5,439,632)	5,348,368	5,289,702	98.90%
Totals:			155,910,000	(23,698,924)	132,211,076	128,328,216	97.06%

Exhibit 2-6B

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 16
November 1, 2008 through October 31, 2009

California Gas Transmission- Redwood Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	608,766	30	18,262,980	(937,980)	17,325,000	16,718,436	96.50%
Dec-08	608,766	31	18,871,746	(1,347,973)	17,523,773	17,690,684	100.95%
Jan-09	608,766	31	18,871,746	(1,297,691)	17,574,055	17,587,739	100.08%
Feb-09	608,766	28	17,045,448	(1,261,120)	15,784,328	15,784,265	100.00%
Mar-09	608,766	31	18,871,746	(4,408,169)	14,463,577	14,757,152	102.03%
Apr-09	608,766	30	18,262,980	(1,405,980)	16,857,000	17,058,572	101.20%
May-09	608,766	31	18,871,746	(3,040,046)	15,831,700	15,890,655	100.37%
Jun-09	608,766	30	18,262,980	(6,255,600)	12,007,380	11,951,112	99.53%
Jul-09	608,766	31	18,871,746	(8,271,637)	10,600,109	10,576,151	99.77%
Aug-09	608,766	31	18,871,746	(8,359,987)	10,511,759	10,479,791	99.70%
Sep-09	608,766	30	18,262,980	(8,092,350)	10,170,630	10,308,755	101.36%
Oct-09	608,766	31	18,871,746	(2,525,508)	16,346,238	16,106,042	98.53%
Totals:			222,199,590	(47,204,041)	174,995,549	174,909,354	99.95%

California Gas Transmission-Silverado Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at Topock	Percent of Utilization
Nov-08	1,000	30	30,000	(30,000)	-	-	100.00%
Dec-08	1,000	31	31,000	(31,000)	-	-	100.00%
Jan-09	1,000	31	31,000	(31,000)	-	-	100.00%
Feb-09	1,000	28	28,000	(28,000)	-	-	100.00%
Mar-09	1,000	31	31,000	(31,000)	-	-	100.00%
Apr-09	1,000	30	30,000	(30,000)	-	-	100.00%
May-09	1,000	31	31,000	(31,000)	-	-	100.00%
Jun-09	1,000	30	30,000	(30,000)	-	-	100.00%
Jul-09	1,000	31	31,000	(31,000)	-	-	100.00%
Aug-09	1,000	31	31,000	(31,000)	-	-	100.00%
Sep-09	1,000	30	30,000	(30,000)	-	-	100.00%
Oct-09	1,000	31	31,000	(31,000)	-	-	100.00%
Totals:			365,000	(365,000)	-	-	100.00%

Footnote: **(1) Includes any capacity assigned to Core Transport Agent (CTA) as well as releases to other parties.**
(2) Utilization may reflect interruptible transportation which can result in a % above 100%.

Exhibit 2-6B

Pacific Gas and Electric
Management of Firm Storage Inventory
CPIM Year 16
November 1, 2008 through October 31, 2009

Predetermined Storage

Month/Year	Natural Gas Nominations (MMBtus)	Inventory Adjustments (MMBtus)	EOM Inventory Level
Beginning Inventory As of 10/31/2008			**32,674,687**
Prior Period Adj:		(1,000,000)	31,674,687
Nov-08	(860,000)	-	30,814,687
Dec-08	(11,682,000)	395,829	19,528,516
Jan-09	(11,313,000)	-	8,215,516
Feb-09	(5,508,000)	64,320	2,771,836
Mar-09	(2,488,000)	260,889	544,725
Apr-09	5,440,610	-	5,985,335
May-09	5,266,000	50,000	11,301,335
Jun-09	4,660,055	-	15,961,390
Jul-09	4,327,693	-	20,289,083
Aug-09	4,089,000	-	24,378,083
Sep-09	3,615,000	326,472	28,319,555
Oct-09	2,335,000	468,307	31,122,862
EOY Inventory:	(2,117,642)	565,817	**31,122,862**

Exhibit 2-7A

Pacific Gas and Electric
Management of Incremental Storage Inventory
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/Year	Natural Gas Injections/ Nominations (MMBtus)	Inventory Adjustments (MMBtus)	EOM Inventory Level (MMBtus)
	CGT and Lodi Gas Storage		
Nov-08	1,000,000	-	1,000,000
Dec-08	1,000,000	(50,000)	1,950,000
Jan-09	950,000	-	2,900,000
Feb-09	300,000	(650,000)	2,550,000
Mar-09	-	(300,000)	2,250,000
Apr-09	125,000	-	2,375,000
May-09	152,500	-	2,527,500
Jun-09	227,500	-	2,755,000
Jul-09	305,000	-	3,060,000
Aug-09	870,000	-	3,930,000
Sep-09	957,500	-	4,887,500
Oct-09	1,000,000	-	5,887,500
EOY Inventory:	6,887,500	(1,000,000)	36,072,500

Exhibit 2-7B

Pacific Gas and Electric Company
Fixed Transportation and Storage Costs
CPIM Year 16
November 1, 2008 through October 31, 2009

	Canadian Pipelines				U S Interstate Pipelines					CA Intrastate Pipelines					CA Intrastate Storage						
Month/ Year	Trans-Canada BC System	Nova Gas Transmission Ltd.	Sub-Total	%	Gas Transmission NW	EPNG Pipeline	Transwestern Pipeline	Sub-Total	%	CGT - Baja	CGT Redwood	CGT Silverado	Sub-Total	%	CGT Firm Contracts	CGT Incremental Contracts	Lodi Contracts	Sub-Total	%	Total	%
Nov-08	$ 892,198	$ 2,323,733	$ 3,215,931	7%	$ 5,859,371	$ 1,764,427	$ 1,349,813	$ 8,973,611.00	8%	$ 2,359,721	$ 1,961,537	$ 3,147	$ 4,324,405.00	7%	$ 3,462,698	$ 70,833	$ 85,000	$ 3,618,531.00	8%	$ 20,132,478.00	8%
Dec-08	916,091	2,385,962	3,302,053	8%	6,054,683	2,239,637	1,735,287	10,029,607.00	9%	4,962,895	1,920,040	3,147	6,886,082.00	12%	3,462,698	70,833	85,500	3,619,031.00	8%	23,836,773.00	9%
Jan-09	836,318	2,603,580	3,439,898	8%	6,054,683	2,558,720	1,735,287	10,348,690.00	9%	4,900,442	1,905,765	3,115	6,809,322.00	12%	3,462,698	70,833	85,000	3,618,531.00	8%	24,216,441.00	9%
Feb-09	814,299	2,535,031	3,349,330	8%	5,468,746	2,167,145	1,567,356	9,203,247.00	8%	4,904,319	1,895,078	3,115	6,802,512.00	12%	3,462,698	70,833	86,500	3,620,031.00	8%	22,975,120.00	9%
Mar-09	821,066	2,556,099	3,377,165	8%	6,054,683	1,200,984	1,395,000	8,650,667.00	8%	2,304,469	1,887,820	3,115	4,195,404.00	7%	3,462,698	70,833	88,000	3,621,531.00	8%	19,844,767.00	8%
Apr-09	845,293	2,631,522	3,476,815	8%	5,859,371	1,862,236	1,350,000	9,071,607.00	8%	2,270,957	1,888,939	3,115	4,163,011.00	7%	3,401,146	66,667	75,750	3,543,563.00	8%	20,254,996.00	8%
May-09	918,629	2,859,827	3,778,456	9%	6,054,683	1,770,813	1,395,000	9,220,496.00	8%	2,272,223	1,884,905	3,115	4,160,243.00	7%	3,401,861	66,667	75,775	3,544,303.00	8%	20,703,498.00	8%
Jun-09	883,689	2,751,052	3,634,741	8%	5,859,371	1,727,225	1,350,000	8,936,596.00	8%	2,420,080	1,883,379	3,115	4,306,574.00	7%	3,401,861	66,667	75,750	3,544,278.00	8%	20,422,189.00	8%
Jul-09	944,063	2,939,005	3,883,068	9%	6,054,683	1,697,935	1,395,000	9,147,618.00	8%	2,457,441	1,889,070	3,115	4,349,626.00	7%	3,401,861	66,667	75,775	3,544,303.00	8%	20,924,615.00	8%
Aug-09	936,518	2,915,518	3,852,036	9%	6,054,683	1,771,387	1,395,000	9,221,070.00	8%	2,457,080	1,879,489	3,115	4,339,684.00	7%	3,401,861	66,667	75,775	3,544,303.00	8%	20,957,093.00	8%
Sep-09	943,143	2,936,140	3,879,283	9%	5,859,371	1,771,388	1,350,000	8,980,759.00	8%	2,461,926	1,879,261	3,115	4,344,302.00	7%	3,398,617	66,667	75,750	3,541,034.00	8%	20,745,378.00	8%
Oct-09	952,649	2,965,737	3,918,386	9%	6,054,683	1,771,387	1,395,000	9,221,070.00	8%	2,423,214	1,873,469	3,115	4,299,798.00	7%	3,398,617	66,667	75,425	3,540,709.00	8%	20,979,963.00	8%
Totals:	$ 10,703,956	$ 32,403,206	$ 43,107,162	100%	$ 71,289,011	$ 22,303,284	$ 17,412,743	$ 111,005,038.00	100%	$ 36,194,767	$ 22,748,752	$ 37,444	$ 58,980,963.00	100%	$ 41,119,314	$ 820,834	$ 960,000	$ 42,900,148.00	100%	$ 255,993,311.00	100%

Pacific Gas and Electric Company
Summary of Firm Storage Injections and Withdrawals
CPIM Year 16
November 1, 2008 through October 31, 2009

	PG&E Firm Storage			CGT Incremental Storage			Lodi Incremental Storage		
Month	**injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**	**injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**	**injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**
Beginning Balance:			**31,674,687**			**500,000**			**500,000**
Nov-08	(860,000)	-	30,814,687	0	0	500,000	0	0	500,000
Dec-08	(11,682,000)	395,829	19,528,516	0	0	500,000	0	(50,000)	450,000
Jan-09	(11,313,000)	0	8,215,516	0	0	500,000	0	0	450,000
Feb-09	(5,508,000)	64,320	2,771,836	0	(500,000)	-	0	(150,000)	300,000
Mar-09	(2,488,000)	260,889	544,725	0	0	-	0	(300,000)	-
Apr-09	5,440,610		5,985,335	50,000	0	50,000	75,000	0	75,000
May-09	5,266,000	50,000	11,301,335	(50,000)	0	-	77,500	0	152,500
Jun-09	4,660,055		15,961,390	0	0	-	75,000	0	227,500
Jul-09	4,327,693		20,289,083	0	0	-	77,500	0	305,000
Aug-09	4,089,000		24,378,083	487,500	0	487,500	77,500	0	382,500
Sep-09	3,992,405	(50,933)	28,319,555	12,500	0	500,000	75,000	0	457,500
Oct-09	2,335,000	468,307	31,122,862	0	0	500,000	42,500	0	500,000
Ending Balance:	(1,740,237)	1,188,412	31,122,862	500,000	(500,000)	500,000	500,000	(500,000)	500,000

Exhibit 2-7D

Table II
Pacific Gas and Electric Company
CPIM Performance
CPIM Year 16
November 1, 2008 through October 31, 2009

	Interstate and California Gas Purchases			Pipeline Charges		Total CPIM Performance					
Month Year	**Commodity (1) Actuals**	**Commodity (1) Benchmark**	**Benchmark Less Actuals (Over) Under**	**Actuals (2)**	**Benchmark (3)**	**Actuals**	**Benchmark**	**Benchmark Less Actuals (Over) Under**	**Deadband Upper Limit (4)**	**Deadband Lower Limit (5)**	**(Over)/Under Deadband**
Nov-08	$90,968,802	$76,476,057	($14,492,745)	$20,106,931	$20,132,478	$111,075,733	$96,608,535	($14,467,198)	$98,138,056	$95,843,774	($15,231,959)
Dec-08	$183,560,925	$191,799,195	$8,238,270	$21,552,024	$23,836,773	$205,112,949	$215,635,968	$10,523,019	$219,471,952	$213,717,976	8,605,027
Jan-09	$148,129,327	$141,990,470	($6,138,857)	$24,321,236	$24,216,441	$172,450,563	$166,206,911	($6,243,652)	$169,046,720	$164,787,006	(7,663,557)
Feb-09	$101,337,921	$107,574,339	$6,236,418	$19,638,965	$22,975,120	$120,976,886	$130,549,459	$9,572,573	$132,700,946	$129,473,716	8,496,830
Mar-09	$82,934,714	$85,198,028	$2,263,314	$18,467,388	$19,844,767	$101,402,102	$105,042,795	$3,640,693	$106,746,756	$104,190,815	2,788,713
Apr-09	$79,756,776	$81,401,454	$1,644,678	$20,166,123	$20,254,996	$99,922,899	$101,656,450	$1,733,551	$103,284,479	$100,842,435	919,536
May-09	$53,510,128	$56,639,627	$3,129,499	$19,981,639	$20,703,498	$73,491,767	$77,343,125	$3,851,358	$78,475,918	$76,776,729	3,284,962
Jun-09	$48,382,302	$49,466,178	$1,083,876	$18,361,506	$20,422,189	$66,743,808	$69,888,367	$3,144,559	$70,877,691	$69,393,705	2,649,897
Jul-09	$45,766,122	$49,444,865	$3,678,743	$18,388,552	$20,924,615	$64,154,674	$70,369,480	$6,214,806	$71,358,377	$69,875,031	5,720,357
Aug-09	$48,016,532	$50,442,905	$2,426,373	$18,026,447	$20,957,093	$66,042,979	$71,399,998	$5,357,019	$72,408,856	$70,895,569	4,852,590
Sep-09	$39,236,220	$39,810,155	$573,935	$17,700,063	$20,745,378	$56,936,283	$60,555,533	$3,619,250	$61,351,736	$60,157,431	3,221,148
Oct-09	$56,679,615	$60,579,345	$3,899,730	$18,800,543	$20,979,962	$75,480,158	$81,559,307	$6,079,149	$82,770,894	$80,953,514	5,473,356
Totals	$978,279,384	$990,822,618	$12,543,234	$235,511,417	$255,993,310	$1,213,790,801	$1,246,815,928	$33,025,127	$1,266,632,380	$1,236,907,702	$ 23,116,901

CPIM Shareholder Reward: $ 4,623,381

Footnotes:

(1) Commodity costs consist of Canadian and U.S. natural gas purchases and PG&E's CityGate volumetric transportation costs.

(2) Includes intrastate, interstate and Canadian pipeline reservation charges net of capacity release revenue.

(3) Benchmark is based on fixed transportation and storage costs.

(4) "Upper Limit" equal Benchmark +2.0 % of Commodity benchmark

(5) "Lower Limit" equal Benchmark - 1.0% of Commodity Benchmark.

Pacific Gas and Electric
City-Gate Indices
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/Year	California Topock (Firm)	Kingsgate	San Juan	AECO	NGI Daily PG&E CityGate
39,753.00	3.86	6.02	3.05	5.82	6.44
39,783.00	5.51	6.41	4.91	6.21	6.08
39,814.00	5.39	5.88	5.12	5.67	4.66
39,845.00	3.77	4.93	3.33	4.72	4.06
39,873.00	3.38	4.19	2.90	3.99	3.53
39,904.00	3.44	3.73	2.82	3.52	3.39
39,934.00	2.98	3.44	2.70	3.21	3.33
39,965.00	3.20	3.43	2.85	3.21	3.69
39,995.00	3.41	3.44	3.20	3.20	3.50
40,026.00	3.47	3.24	3.41	3.00	2.90
40,057.00	2.76	2.91	2.67	2.68	4.02
40,087.00	3.81	3.28	3.65	3.04	5.22

Pacific Gas and Electric
Schedule of Miscellaneous Costs and Revenues
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/ Year	Broker Fees	Reservation Fees	Cochrane Extraction Revenue	OFO Charges	Usage Storage Charges	Total
Nov-08	$ 11,169.00	$ 430,000.00	$ (202,340.00)	$ -	$ -	$ 238,829.00
Dec-08	21,525.00		(126,191.00)	2,308.00	-	(102,358.00)
Jan-09	13,397.00	-	(570,101.00)	-	-	(556,704.00)
Feb-09	15,170.00	-	(555,927.00)	(2,308.00)	-	(543,065.00)
Mar-09	18,247.00	-	(546,445.00)	-	-	(528,198.00)
Apr-09	14,723.00	-	(866,840.00)	-	8,500.00	(843,617.00)
May-09	19,062.00	-	(934,243.00)	-	-	(915,181.00)
Jun-09	12,292.00	-	(700,737.00)	-	-	(688,445.00)
Jul-09	25,418.00	-	(540,047.00)	-	-	(514,629.00)
Aug-09	13,662.00	-	(640,497.00)	-	-	(626,835.00)
Sep-09	16,348.00	-	(649,501.00)	-	-	(633,153.00)
Oct-09	13,921.00	-	(989,754.00)	-	-	(975,833.00)
Totals:	$ 194,934.00	$ 430,000.00	$ (7,322,623.00)	$ -	$ 8,500.00	$ (6,689,189.00)

Exhibit 2-8C

Pacific Gas and Electric Company
Modified Determined Usage
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/ Year	Burner Tip Modified Determined Usage a	Burner Tip Modified Determined Gross Up b	Modified Determined Converted to MMBtus c	Operating Imbalance Adjustment (MMBtus) d	Firm Storage (CGT) Injection/ (Withdrawal) (1) e	Incremental Storage (CGT) Injection/ (Withdrawal) (1)	Incremental Storage (Lodi) Injection/ (Withdrawal) (1)	Benchmark Load at CityGate (MMBtus) g
		(a) x 1+.033)						(c.) +(d)+(e)+(f)=(g)
Nov-08	202,835,226	209,528,788	20,952,882	(19,799)	(3,170,969)			17,762,114
Dec-08	430,726,093	444,940,055	44,494,010	(17,721)	(10,464,197)		(50,000)	33,962,092
Jan-09	371,481,193	383,740,070	38,374,009	(15,172)	(11,876,754)		-	26,482,083
Feb-09	304,801,298	314,859,741	31,485,975	(9,064)	(4,122,259)	(500,000)	(150,000)	26,704,652
Mar-09	257,376,936	265,870,375	26,587,039	(8,059)	(2,219,678)	-	(300,000)	24,059,302
Apr-09	181,936,369	187,940,268	18,794,029	166,626	5,978,864	-	75,750	25,015,269
May-09	129,652,312	133,930,838	13,393,086	170,108	5,575,613	-	78,275	19,217,082
Jun-09	110,660,571	114,312,370	11,431,238	181,587	4,839,496	-	75,750	16,528,071
Jul-09	103,246,523	106,653,659	10,665,366	210,905	4,490,729	-	78,275	15,445,275
Aug-09	104,750,618	108,207,389	10,820,739	256,761	4,024,452	492,930	78,275	15,673,157
Sep-09	106,569,785	110,086,590	11,008,660	292,958	3,467,967	12,640	75,750	14,857,975
Oct-09	152,278,643	157,303,838	15,730,385	320,752	3,091,900	-	42,925	19,185,962
Totals:	2,456,315,567	2,532,461,350	253,246,139	1,529,882	(384,836)	5,570	5,000	254,401,755

(1) Includes injection shrinkage of 1.1% CGT; 1.0% Lodi

Exhibit 2-8D

Pacific Gas and Electric
Review of Southwest and CA Index at CityGate
CPIM Year 16
November 1, 2008 through December 31, 2009

Month/Year	Southwest & CA Index	CGT Shrinkage Rate	Shrinkage (1-b)	Gross-Up to CityGate (a/.c)	CGT Volumetric Rate	Southwest & CA Index at CityGate
	a	b	c	d	e	f
Nov-08	3.7200	1.30%	98.70%	3.7690	0.0903	3.859297
Dec-08	5.3500	1.30%	98.70%	5.4205	0.0903	5.510766
Jan-09	5.2300	1.30%	98.70%	5.2989	0.0894	5.388286
Feb-09	3.6300	1.30%	98.70%	3.6778	0.0894	3.767212
Mar-09	3.2500	1.30%	98.70%	3.2928	0.0894	3.382206
Apr-09	3.3100	1.30%	98.70%	3.3536	0.0894	3.442997
May-09	2.8500	1.30%	98.70%	2.8875	0.0894	2.976938
Jun-09	3.0700	1.30%	98.70%	3.1104	0.0894	3.199836
Jul-09	3.2800	1.30%	98.70%	3.3232	0.0894	3.412602
Aug-09	3.3400	1.30%	98.70%	3.3840	0.0894	3.473392
Sep-09	2.6400	1.30%	98.70%	2.6748	0.0894	2.764172
Oct-09	3.6700	1.30%	98.70%	3.7183	0.0894	3.807738

Exhibit 2-8E

Pacific Gas and Electric
Review of Malin Index (AECO)
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/Year	AECO Index (Can $/MMBtu) (2)	Conversion of AECO Index (Can $/MMBtu) (2)	ANG Fuel %	Gross-up of AECO Index (b/(1 c)	Monthly Exchange Rate (3)	AECO/Kingsgate Index (e/f)	GTNC Fuel % Rate	Total Kingsgate Index	GTNC Volumetric Rate	Total Malin Index	CGT Fuel %	Gross-up of Malin Index (k/(1-l)	CGT Cost per MMBtu	Total CityGate Index (m + n)
a	b	c	d	e	f	g	h	I	j	k	l	m	n	o
Nov-08	6.556800	6.917791	0.0110340	6.994974	1.251408	5.5896828	0.017761340	5.6907583	0.01149936	5.70225761	0.0130	5.777363	0.0464	5.8237633
Dec-08	6.830000	7.206032	0.0090190	7.271615	1.218769	5.9663605	0.017148880	6.0704621	0.01149936	6.0819615	0.0130	6.162068	0.0464	6.2084683
Jan-09	6.217100	6.559389	0.0099730	6.625464	1.222315	5.4204231	0.020823640	5.5356964	0.01149936	5.5471958	0.0130	5.620259	0.0459	5.6661591
Feb-09	5.329300	5.622710	0.0070030	5.662363	1.255367	4.5105244	0.020823640	4.6064474	0.01149936	4.6179468	0.0130	4.678771	0.0459	4.7246708
Mar-09	4.475900	4.722325	0.0070030	4.755629	1.245020	3.8197208	0.015923960	3.8815302	0.01149936	3.8930295	0.0130	3.944305	0.0459	3.9902055
Apr-09	3.817100	4.027254	0.0099730	4.067823	1.209336	3.3636828	0.015923960	3.4181126	0.01149936	3.4296120	0.0130	3.474784	0.0459	3.5206842
May-09	3.237600	3.415849	0.0070030	3.439939	1.112793	3.0912660	0.007349520	3.1141536	0.01149936	3.1256529	0.0130	3.166822	0.0459	3.2127216
Jun-09	3.349500	3.533910	0.0090190	3.566072	1.156792	3.0827257	0.010411820	3.1151602	0.01149936	3.1266596	0.0130	3.167842	0.0459	3.2137415
Jul-09	3.136700	3.309394	0.0060480	3.329531	1.082814	3.0748874	0.009186900	3.1033980	0.01149936	3.1148974	0.0130	3.155924	0.0459	3.2018244
Aug-09	2.901200	3.060928	0.0130500	3.101402	1.091536	2.8413188	0.022048560	2.9053782	0.01149936	2.9168776	0.0130	2.955296	0.0459	3.0011964
Sep-09	2.558300	2.699150	0.0119890	2.731903	1.083870	2.5205076	0.024498400	2.5838067	0.01149936	2.5953061	0.0130	2.629489	0.0459	2.6753894
Oct-09	2.872900	3.031070	0.0140050	3.074123	1.073053	2.8648384	0.025110860	2.9386300	0.01149936	2.9501293	0.0130	2.988986	0.0459	3.0348861

Footnotes:
(1) AECO Index (Canadian Enerdata 30-day baseload Index at AECO C).
(2) A conversation rate of 1.055056 is used.
(3) This is the Canadian exchange rate at date of settlement.

Pacific Gas and Electric
Review of San Juan Index
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/Year	San Juan Index per MMBtu	TW Contract Fuel %	Gross-up of San Juan Index	TW Volumetric Rate per MMBtus	Gross-up of San Juan Index Vol. Rate	CGT Fuel %	Gross Up of San Juan Index	CGT-Baja Cost per MMBtu	Total CityGate Index/MMBtu
	(a)	(b)	(.c)	(d)	(e)	(f)	(g)	(h)	(i)
			(a/1-(b))		(c+d)		(e/-1-(f)		(g+h)
Nov-08	2.8400	0.0245	2.911328	0.0128	2.924128	0.0130	2.962642	0.0903	3.052942
Dec-08	4.6300	0.0245	4.746284	0.0128	4.759084	0.0130	4.821767	0.0903	4.912067
Jan-09	4.8300	0.0245	4.951307	0.0128	4.964107	0.0130	5.029490	0.0894	5.118890
Feb-09	3.1100	0.0245	3.188109	0.0128	3.200909	0.0130	3.243069	0.0894	3.332469
Mar-09	2.6900	0.0245	2.757560	0.0128	2.770360	0.0130	2.806849	0.0894	2.896249
Apr-09	2.6200	0.0245	2.685802	0.0128	2.698602	0.0130	2.734146	0.0894	2.823546
May-09	2.5000	0.0245	2.562788	0.0128	2.575588	0.0130	2.609512	0.0894	2.698912
Jun-09	2.6500	0.0245	2.716556	0.0128	2.729356	0.0130	2.765305	0.0894	2.854705
Jul-09	2.9800	0.0245	3.054844	0.0128	3.067644	0.0130	3.108048	0.0894	3.197448
Aug-09	3.1800	0.0245	3.259867	0.0128	3.272667	0.0130	3.315772	0.0894	3.405172
Sep-09	2.4700	0.0245	2.532035	0.0128	2.544835	0.0130	2.578353	0.0894	2.667753
Oct-09	3.4200	0.0245	3.505894	0.0130	3.518894	0.0130	3.565243	0.0894	3.654643

Exhibit 2-8G

Pacific Gas and Electric
Review of Kingsgate Index
CPIM Year 16
November 1, 2008 through October 31, 2009

Month/Year (a)	Kingsgate Index per MMBtu (b)	GTNC Fuel % (.c)	Gross-Up of Kingsgate Index (d)	GTNC Volumetic Rate (e)	Total Index at Malin (f)	CGT Fuel % (g)	Gross-Up of Malin Index (h)	CGT-Redwood Volumetric Rate (i)	Total CityGate Index per MMBtu (j)
			(a/1-(b))		(c+d)		(e/-1-(f)		(g+h)
Nov-08	5.779255	0.017761	5.883758	0.011499360	5.895258	0.0130	5.972906	0.0464	6.019306
Dec-08	6.160723	0.017149	6.268216	0.011499360	6.279715	0.0130	6.362427	0.0464	6.408827
Jan-09	5.623281	0.020824	5.742868	0.011499360	5.754368	0.0130	5.830160	0.0459	5.876060
Feb-09	4.707594	0.020824	4.807708	0.011499360	4.819207	0.0130	4.882682	0.0459	4.928582
Mar-09	4.018427	0.015924	4.083452	0.011499360	4.094951	0.0130	4.148887	0.0459	4.194787
Apr-09	3.568716	0.015924	3.626464	0.011499360	3.637963	0.0130	3.685879	0.0459	3.731779
May-09	3.313584	0.073495	3.576435	0.011499360	3.587934	0.0130	3.635192	0.0459	3.681092
Jun-09	3.296917	0.010412	3.331605	0.011499360	3.343104	0.0130	3.387137	0.0459	3.433037
Jul-09	3.303195	0.091869	3.637355	0.011499360	3.648855	0.0130	3.696914	0.0459	3.742814
Aug-09	3.069014	0.022049	3.138207	0.011499360	3.149706	0.0130	3.191192	0.0459	3.237092
Sep-09	2.749628	0.024498	2.818681	0.011499360	2.830181	0.0130	2.867457	0.0459	2.913357
Oct-09	3.096625	0.025111	3.176387	0.011499360	3.187886	0.0130	3.229875	0.0459	3.275775

Exhibit 2-8H

Pacific Gas and Electric
Benchmark Commodity Costs and Reservation Charges
CPIM Year 17
November 1, 2009 through October 31, 2010

Benchmark by Pipeline	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Commodity Benchmark
California Firm	$ 140,220	$ 148,335	$ 188,542	$ 157,528	$ 154,287	$ 124,980	$ 129,766	$ 119,790	$ 145,173	$ 136,679	$ 107,310	$ 121,582	$ 1,674,192
Kingsgate	1,422,750	1,277,913	1,567,081	1,449,336	1,279,711	1,416,210	1,341,494	872,760	2,042,900	2,046,961	1,845,150	779,774	17,342,040
San Juan	31,124,247	49,591,648	66,781,853	46,134,662	33,618,440	35,028,705	31,767,874	21,123,570	13,571,149	12,920,149	9,953,370	12,813,549	364,429,216
AECO	74,374,870	81,214,201	83,351,834	77,982,942	85,822,828	68,403,754	52,555,423	43,169,536	54,560,172	52,565,642	42,736,488	52,004,126	768,741,816
Topock Firm	-	11,179,170	5,396,999	785,994	-	-	-	-	-	-	-	-	17,362,163
CityGate As Available	5,655,321	12,209,348	205,793	-	9,073,622	13,375,615	246,288	-	-	-	-	-	40,765,987
CPIM Market Benchmark :	$ 112,717,408	$ 155,620,615	$ 157,492,102	$ 126,510,462	$ 129,948,888	$ 118,349,264	$ 86,040,845	$ 65,285,656	$ 70,319,394	$ 67,669,431	$ 54,642,318	$ 65,719,031	$ 1,210,315,414
Benchmark Reservation Charges													
Foothills Pipe Lines Ltd.	$ 965,673	$ 974,669	$ 1,399,856	$ 1,414,991	$ 1,458,609	$ 1,475,115	$ 1,404,236	$ 1,423,959	$ 1,494,228	$ 1,459,890	$ 1,501,059	$ 1,511,722	16,484,007
California Gas Transmission	7,591,908	10,197,731	10,375,791	10,374,334	7,769,171	7,694,162	7,569,606	7,710,670	7,761,770	7,760,335	7,776,906	7,696,095	100,278,479
El Paso Natural Gas Company	1,771,387	1,766,618	1,771,388	1,771,388	1,771,388	1,771,388	1,771,388	1,755,236	1,905,107	1,905,107	1,899,809	1,905,107	21,765,311
Kern River Gas Transmission Refund	-	0	0	0	(8,392)	0	0	0	0	0	0	0	(8,392)
El Paso Natural Gas Company Refund	-	0	0	0	0	(72,000)	0	0	0	(927,080)	(821,912)	0	(1,820,992)
Lodi Gas Storage, Inc.	75,000	76,500	75,000	75,500	77,500	75,750	75,775	75,750	75,775	75,775	75,675	75,000	909,000
Nova Gas Transmission. Ltd.	3,006,280	3,034,285	3,516,662	3,513,185	3,621,481	3,662,462	3,486,481	3,535,451	3,576,210	3,494,026	3,592,558	3,618,078	41,657,159
Gas Transmission Northwest Corp.	5,859,371	6,054,683	6,054,683	5,468,746	6,054,683	5,859,371	6,054,683	5,859,371	6,054,683	6,054,683	5,859,371	6,054,683	71,289,011
Transwestern Pipeline Company	1,350,000	1,868,060	1,870,664	1,689,632	1,395,000	1,646,550	1,701,435	1,646,550	1,701,435	1,701,435	1,646,550	1,701,435	19,918,746
Total Benchmark Reservation Charges:	20,619,619	23,972,546	25,064,044	24,307,776	22,139,440	22,112,798	22,063,604	22,006,987	22,569,208	21,524,171	21,530,016	22,562,120	270,472,329
													-
Total Benchmark Costs:	$ 133,337,027	$ 179,593,161	$ 182,556,146	$ 150,818,238	$ 152,088,328	$ 140,462,062	$ 108,104,449	$ 87,292,643	$ 92,888,602	$ 89,193,602	$ 76,172,334	$ 88,281,151	$ 1,480,787,743

Exhibit 3-1A

Pacific Gas and Electric
Benchmark Sequenced Gas Volume
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	California Firm	Kingsgate	San Juan	AECO	Topock Topock Firm	CityGate as Available	Total Commodity Benchmark at CityGate
Nov-09	30,000	277,860	6,868,295	15,244,780	0	1,362,746	23,783,681
Dec-09	31,000	252,805	10,893,574	16,881,483	2,336,227	2,179,783	32,574,872
Jan-10	31,000	275,652	11,040,873	15,469,341	887,312	34,529	27,738,707
Feb-10	28,000	248,976	8,190,459	14,123,827	139,707	0	22,730,969
Mar-10	31,000	229,927	6,825,030	16,323,414	0	1,788,662	25,198,033
Apr-10	30,000	311,040	8,710,914	16,132,971	0	3,028,173	28,213,098
May-10	31,000	332,878	7,839,214	14,084,213	0	59,634	22,346,939
Jun-10	30,000	211,410	5,363,940	11,278,985	0	0	16,884,335
Jul-10	31,000	447,237	2,981,704	12,795,558	0	0	16,255,499
Aug-10	31,000	504,463	2,981,704	14,009,786	0	0	17,526,953
Sep-10	30,000	488,190	2,885,520	12,331,901	0	0	15,735,611
Oct-10	31,000	195,579	3,369,407	14,147,169	0	0	17,743,155
Totals:	365,000	3,776,017	77,950,634	172,823,428	3,363,246	8,453,527	266,731,852

Exhibit 3-1B

Pacific Gas and Electric
Total Commodity Benchmark
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	California Firm	Kingsgate	San Juan	AECO	Topock Firm	CityGate as Available	Total Commodity Benchmark
Nov-09	$ 140,220	$ 1,422,750	$ 31,124,247	$ 74,374,870	$ -	$ 5,655,321	$ 112,717,408
Dec-09	148,335	1,277,913	49,591,648	81,214,201	11,179,170	12,209,348	155,620,615
Jan-10	188,542	1,567,081	66,781,853	83,351,834	5,396,999	205,793	157,492,102
Feb-10	157,528	1,449,336	46,134,662	77,982,942	785,994	0	126,510,462
Mar-10	154,287	1,279,711	33,618,440	85,822,828	0	9,073,622	129,948,888
Apr-10	124,980	1,416,210	35,028,705	68,403,754	0	13,375,615	118,349,264
May-10	129,766	1,341,494	31,767,874	52,555,423	0	246,288	86,040,845
Jun-10	119,790	872,760	21,123,570	43,169,536	0	0	65,285,656
Jul-10	145,173	2,042,900	13,571,149	54,460,172	0	0	70,219,394
Aug-10	136,679	2,046,961	12,920,149	52,565,642	0	0	67,669,431
Sep-10	107,310	1,845,150	9,953,370	42,736,488	0	0	54,642,318
Oct-10	121,582	779,774	12,813,549	52,004,126	0	0	65,719,031
Totals:	$ 1,674,192	$ 17,342,040	$ 364,429,216	$ 768,641,816	$ 17,362,163	$ 40,765,987	$ 1,210,215,414

Exhibit 3-1C

Pacific Gas and Electric
Actual Commodity Costs by Pipeline
CPIM Year 17
November 1, 2009 through October 31, 2010

Gas Purchases by Pipeline:	**Nov-09**	**Dec-09**	**Jan-10**	**Feb-10**	**Mar-10**	**Apr-10**	**May-10**	**Jun-10**	**Jul-10**	**Aug-10**	**Sep-10**	**Oct-10**	**Total Commodity Costs:**
CGT Baja	$ 734,873	$ 1,560,296	$ 1,484,058	$ 1,140,483	$ 949,651	$ 883,281	$ 861,566	$ 557,735	$ 402,486	$ 214,398	$ 522,102	$ 634,529	$ 9,945,458
CGT-City-Gate	(8,298,424)	(2,543,127)	(21,995,155)	(25,410,760)	(15,727,000)	758,108	(11,535,750)	(17,594,554)	(12,275,592)	3,610,017	(15,514,828)	(26,195,877)	(152,722,942)
CGT-Redwood	826,452	809,891	794,151	710,380	863,690	1,112,484	782,188	660,496	649,722	649,431	632,331	790,267	9,281,483
EPNG-Basin	23,270,010	27,481,820	33,408,826	28,394,296	29,145,669	23,148,390	23,491,701	9,558,714	12,531,128	4,238,302	11,682,582	19,166,269	245,517,707
EPNG-Topock	(3,997,572)	14,018,491	13,867,942	3,605,242	242,368	(435,088)	(2,962,467)	(217,327)	(1,361,707)	(606,346)	3,520,565	(641,002)	25,033,099
Kern River Daggett	-	48,300	117,564	375,880	35,830	62,783	-	-	-	-	-	-	640,357
Kern River-Opal	-	-	-	-	-	-	-	-	-	-	-	-	-
Kern River Station	-	-	-	-	-	-	-	-	-	-	-	-	-
NGTL-AECO-NIT	83,013,661	88,081,068	98,434,889	90,360,845	95,262,112	74,683,231	60,448,578	62,678,568	60,772,383	53,868,121	48,475,887	66,478,135	882,557,478
GTNC-All	(2,556,827)	(5,752,665)	(4,956,640)	(4,977,881)	(3,382,679)	(872,294)	(3,359,504)	(6,836,019)	(1,313,650)	(1,186,845)	(1,019,098)	(5,116,858)	(41,330,960)
TW-Basin	15,724,004	31,344,900	40,611,859	34,285,269	21,506,747	7,892	18,295,200	15,314,079	9,506,808	6,676,404	5,503,854	7,404,078	206,181,094
TW-Needles	-	-	-	-	-	-	-	-	-	-	-	-	-
TW-Topock	-	3,138,702	626,623	(3,328,614)	193,709	16,830,736	-	-	-	(36,800)	-	-	17,424,356
Adjustments for Related Costs:													
Hedging Costs	-	-	-	-	-	-	-	-	-	-	-	-	
Miscellaneous Costs & Revenues	(771,228)	(1,134,999)	(1,202,391)	(1,069,048)	(1,157,087)	(1,107,967)	(1,022,373)	(1,090,107)	(751,907)	(826,687)	(419,726)	(1,244,188)	(11,797,708)
Total Commodity Costs:	$ 107,944,949	$ 157,052,677	$ 161,191,726	$ 124,086,092	$ 127,933,010	$ 115,071,556	$ 84,999,139	$ 63,031,585	$ 68,159,671	$ 66,599,995	$ 53,383,669	$ 61,275,353	$ 1,190,729,422

Exhibit 3-2A

Pacific Gas and Electric
Summary of Actual Commodity Costs and Reservation Charges
CPIM Year 17
November 1. 2009 through October 31, 2010

Actual Commodity Costs - by Pipeline		**Actual Costs**
CGT - Baja	$	9,945,458
CGT - City-Gate		(152,722,942)
CGT - Redwood		9,281,483
EPNG - Basin		245,517,707
EPNG - Topock		25,033,099
Kern River - Daggett		640,357
NGTL - AECO-NIT		882,557,478
GTNC-All		(41,330,960)
TW-Basin		206,181,094
TW-Topock		17,424,356
Miscellaneous Costs		(11,803,205)
Total Commodity Costs:	$	1,180,778,467

Actual Commodity Sales - by Pipeline		
CGT - City-Gate	$	182,065,506
EPNG - Basin		13,535,213
EPNG - Topock		11,956,070
NGTL - AECO-NIT		1,893,303
GTNC-All		45,804,921
TW Basin		2,999,933
TW Topock		6,267,593
Total Commodity Sales:	$	264,522,539

Actual Reservation Charges:		
Foothills Pipe Lines, Ltd.	$	16,155,380
California Gas Transmission		92,226,118
El Paso Natural Gas Company		20,499,625
El Paso and Kern River Refunds		(1,829,384)
Lodi Gas Storage, Inc.		909,000
Nova Gas Transmission, Ltd.		39,460,733
Gas Transmission Northwest corp.		70,456,835
Transwestern Pipeline Company		18,501,693
Total Reservation Charges:	$	256,380,000

Net Actual Costs:	$	1,701,681,006

Total Volume in MMBtus: 279,863,168

Exhibit 3-2B

Pacific Gas and Electric
Summary of Actual Commodity Costs and Capacity Reservation Charges
CPIM Year 17
November 1, 2009 through October 31, 2010

Actual Net Commodity Costs:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	YTD Total
Baja Path	$ 40,425,678	$ 77,592,508	$ 93,474,744	$ 74,588,932	$ 52,073,974	$ 41,246,965	$ 42,693,899	$ 27,785,928	$ 25,767,635	$ 15,358,748	$ 21,229,476	$ 27,262,393	$ 539,500,880
Mission Path	2,218,832	4,533,278	418,553	-	8,202,933	7,535,587	-	111,375	1,161,406	4,986,500	76,400	97,700	29,342,564
Redwood Path	85,488,142	89,105,065	99,551,300	91,267,567	96,384,851	76,108,166	61,422,945	63,737,048	62,217,360	56,062,095	49,312,237	67,549,427	898,206,203
Commodity Sales	(19,416,474)	(13,043,176)	(31,050,481)	(40,701,360)	(27,571,661)	(8,711,195)	(18,095,332)	(27,512,659)	(20,234,823)	(8,980,659)	(16,814,737)	(32,389,979)	(264,522,536)
Miscellaneous Costs & Revenues	(771,228)	(1,134,999)	(1,202,391)	(1,069,048)	(1,157,087)	(1,107,967)	(1,022,373)	(1,090,107)	(751,907)	(826,687)	(419,726)	(1,244,188)	(11,797,708)
Total Net Commodity Costs:	$107,944,950	$ 157,052,676	$ 161,191,725	$ 124,086,091	$ 127,933,010	$ 115,071,556	$ 84,999,139	$ 63,031,585	$ 68,159,671	$ 66,599,997	$ 53,383,650	$ 61,275,353	$ 1,190,729,403

Actual Demand Charges	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	YTD Total
TransCanada-B.C. System	$ 965,673	$ 974,669	$ 1,399,856	$ 1,414,991	$ 1,458,609	$ 1,475,115	$ 1,329,808	$ 1,377,524	$ 1,423,720	$ 1,391,091	$ 1,432,602	$ 1,511,722	$ 16,155,380
California Gas Transmission	7,071,408	9,117,381	10,223,891	10,217,534	7,766,071	7,691,162	6,958,906	6,516,461	6,567,495	6,411,059	6,693,905	6,990,845	92,226,118
El Paso Natural Gas Company	1,739,437	1,730,650	1,735,420	1,747,472	1,735,420	1,739,438	1,747,899	1,567,812	1,754,706	1,541,203	1,641,614	1,818,554	20,499,625
El Paso Natural Gas Co. Refund	-	-	-	-	-	(72,000)	-	-	-	(927,080)	(821,912)	-	(1,820,992)
Kern River Gas Transmission Refund	-	-	-	-	(8,392)	-	-	-		-	-	-	(8,392)
Lodi Gas Storage, Inc	75,000	76,500	75,000	75,500	77,500	75,750	75,775	75,750	75,775	75,775	75,675	75,000	909,000
NOVA Gas Transmission Ltd.	3,006,280	3,034,285	3,516,662	3,513,185	3,621,481	3,662,462	3,170,885	3,264,218	3,030,433	2,960,792	3,061,972	3,618,078	39,460,733
Gas Transmission Northwest Corp.	5,814,370	6,054,683	6,054,683	5,468,746	6,054,683	5,859,371	6,008,182	5,772,369	5,818,312	5,842,612	5,654,141	6,054,683	70,456,835
Transwestern Pipeline Company	1,267,672	1,833,010	1,835,614	1,657,974	1,379,678	1,646,550	1,701,435	1,597,005	1,420,885	1,348,035	1,349,550	1,464,285	18,501,693
Total Demand charges:	$ 19,939,840	$ 22,821,178	$ 24,841,126	$ 24,095,402	$ 22,085,050	$ 22,077,848	$ 20,992,890	$ 20,171,139	$ 20,091,326	$ 18,643,487	$ 19,087,547	$ 21,533,167	$ 256,380,000
Total Gas Costs:	$ 127,884,790	$ 179,873,854	$ 186,032,851	$ 148,181,493	$ 150,018,060	$ 137,149,404	$ 105,992,029	$ 83,202,724	$ 88,250,997	$ 85,243,484	$ 72,471,197	$ 82,808,520	$ 1,447,109,403

Exhibit 3-2C

Pacific Gas And Electric Company
Net Purchases by Volume (MMBtus)
CPIM Year 17
November 1, 2009 through October 31, 2010

Pipeline/Purchase Point:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Volume:
CGT City gate	(1,620,843)	(364,730)	(3,670,128)	(4,578,212)	(3,264,252)	169,229	(2,625,590)	(3,981,162)	(2,649,245)	902,609	(4,013,896)	(6,659,993)	(32,356,213)
EPNG-Basin	5,773,366	6,242,615	5,850,549	5,296,068	6,404,690	6,078,578	6,156,727	2,501,466	2,885,252	1,071,895	3,407,479	5,578,235	57,246,920
EPNG-Topock	(887,876)	2,747,258	2,398,111	678,318	52,921	(108,586)	(726,322)	(49,100)	(326,489)	(150,524)	1,017,770	(170,149)	4,475,332
Kern River Daggett	0	10,000	20,097	69,100	7,400	15,700							122,297
NGTL-AECO/NIT	18,205,021	19,152,115	19,133,795	17,265,943	19,197,445	18,705,754	16,908,818	16,778,100	15,406,148	15,450,652	14,922,599	19,208,503	210,334,893
GTNC-All	(616,457)	(1,068,731)	(911,981)	(980,740)	(830,600)	(269,500)	(915,059)	(1,655,320)	(363,096)	(346,950)	(320,300)	(1,529,420)	(9,808,154)
TW Basin	3,662,798	7,082,632	7,074,970	6,439,553	4,673,849	(13,000)	4,733,947	4,110,772	2,189,203	1,612,681	1,689,054	2,057,360	45,313,819
TW Topock	-	569,753	111,396	(614,512)	40,723	4,436,914	-			(10,000)	-	-	4,534,274
Net Purchase Volume	24,516,009	34,370,912	30,006,809	23,575,518	26,282,176	29,015,089	23,532,521	17,704,756	17,141,773	18,530,363	16,702,706	18,484,536	279,863,168

Pacific Gas and Electric
Core Supply Portfolio Composition
CPIM Year 17
November
November 1, 2009 through October 31, 2010

	Volume (MMBtus)				Average Price - U.S Dollars $				Percentage of Total			Total
Month/Year	**SW**	**BL**	**MM**	**Total**	**SW**	**BL**	**MM**	**Total**	**SW**	**BL**	**MM**	**Percent**
Nov-09	3,648,907	3,092,197	21,999,901	28,741,005	$ 3.56	$ 4.31	$ 4.54	$ 4.14	12.7%	10.8%	76.5%	100%
Dec-09	5,343,853	4,077,923	27,204,660	36,626,436	5.39	4.46	4.46	4.77	14.6%	11.1%	74.3%	100%
Jan-10	3,354,378	2,949,166	28,916,710	35,220,254	5.58	5.60	5.38	5.52	9.5%	8.4%	82.1%	100%
Feb-10	2,394,183	3,594,053	25,026,804	31,015,040	5.09	5.33	5.28	5.23	7.7%	11.6%	80.7%	100%
Mar-10	5,180,494	5,268,587	21,575,273	32,024,354	4.42	4.82	4.92	4.72	16.2%	16.5%	67.4%	100%
Apr-10	5,592,788	2,698,505	22,738,076	31,029,369	3.96	3.83	3.95	3.91	18.0%	8.7%	73.3%	100%
May-10	4,680,005	7,805,872	15,325,615	27,811,492	3.72	3.81	3.58	3.70	16.8%	28.1%	55.1%	100%
Jun-10	5,278,854	7,180,490	11,578,317	24,037,661	4.04	3.66	3.67	3.79	22.0%	29.9%	48.2%	100%
Jul-10	2,718,688	8,686,723	10,316,962	21,722,373	3.64	4.11	4.09	3.95	12.5%	40.0%	47.5%	100%
Aug-10	3,428,947	3,857,393	13,570,739	20,857,079	3.59	3.52	3.64	3.58	16.4%	18.5%	65.1%	100%
Sep-10	2,965,322	5,539,439	12,562,238	21,066,999	3.55	3.25	3.24	3.35	14.1%	26.3%	59.6%	100%
Oct-10	5,011,228	6,256,549	15,638,930	26,906,707	3.25	3.51	3.51	3.42	18.6%	23.3%	58.1%	100%
Totals	49,597,647	61,006,897	226,454,225	337,058,769					14.7%	18.1%	67.2%	100%

(1) MMBtu purchases are volumes at point of purchase.
SW = Swing, or daily spot, less than one month duration.
BL= Baseload is a one month duration, purchased for prompt (next) month.
MM= Multi-month is a purchase that is further out than prompt month.

Exhibit 3-3B

Pacific Gas and Electric
Actual Commodity Sales
CPIM Year 17
November 1, 2009 through October 31, 2010

Commodity Sales:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Sales:
CGT City-Gate	$10,517,256	$7,076,405	$22,413,708	$25,410,760	$23,929,933	$6,777,479	$11,535,750	$17,705,929	$13,436,998	$1,376,483	$15,591,228	$26,293,577	$182,065,506
EPNG-Basin	0	0	2,314,149	2,699,088	0	0	26,280	2,230,072	2,621,259	3,611,618	372	32,375	13,535,213
EPNG-Topock	4,051,529	0	88,800	1,326,131	0	700,761	2,962,467	217,327	1,361,707	606,346	0	641,002	11,956,070
NGTL-AECO/NIT	1,441,968	0	105,444	0	39,802	99,715	0	206,374	0	0	0	0	1,893,303
GTNC-All	2,762,888	5,966,772	5,173,457	5,174,223	3,601,926	1,085,030	3,551,683	7,027,629	2,108,905	2,731,388	1,223,137	5,397,883	45,804,921
TW Basin	642,833	0	796,764	18,525	0	48,210	19,152	125,328	705,954	618,025	0	25,142	2,999,933
TW Topock	0	0	158,160	6,072,633	0	0	0	0	0	36,800	0	0	6,267,593
Total Commodity Sales:	$19,416,474	$13,043,177	$31,050,482	$40,701,360	$27,571,661	$8,711,195	$18,095,332	$27,512,659	$20,234,823	$8,980,660	$16,814,737	$32,389,979	$264,522,539
Commodity Volume:													
CGT City-Gate	2,219,404	1,186,793	3,736,428	4,578,212	4,902,099	1,529,458	2,625,590	4,006,162	2,914,198	357,186	4,033,896	6,684,993	38,774,419
EPNG-Basin			380,604	509,867			7,200	541,228	642,691	893,692	97	10,000	2,985,379
EPNG-Topock	902,459		15,000	240,507		173,886	726,322	49,100	326,489	150,524		170,149	2,754,436
NGTL-AECO/NIT	338,387		20,852		9,478	28,435		52,130					449,282
GTNC-All	616,457	1,068,731	911,981	980,740	830,600	269,500	915,059	1,655,320	527,600	746,250	330,300	1,549,220	10,401,758
TW Basin	148,289		123,180	3,597		13,000	4,800	28,965	169,622	169,064		7,808	668,325
TW Topock			25,400	1,126,600						10,000			1,162,000
Total Volume Sales:	4,224,996	2,255,524	5,213,445	7,439,523	5,742,177	2,014,279	4,278,971	6,332,905	4,580,600	2,326,716	4,364,293	8,422,170	57,195,599

Exhibit 3-4A

Pacific Gas and Electric
Actual Sales by Volume (MMBtus)
CPIM Year 17
November 1, 2009 through October 31, 2010

Sales by Pipeline:	Volume (MMBtus)		$
CGT-CityGate	38,774,419		182,065,506
EPNG-Basin	2,985,379		13,535,213
EPNG-Topock	2,754,436		11,956,070
NGTL-AECO/NIT	449,282		1,893,303
GTNC-All	10,401,758		45,804,921
TW Basin	668,325		2,999,933
TW Topock	1,162,000		6,267,593
Total Volume:	57,195,599	$	264,522,539

Exhibit 3-4B

Pacific Gas and Electric
Commodity Volumetric Transport Costs
CPIM Year 17
November 1, 2009 through October 31, 2010

Transport Costs by Pipeline:	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Total Volumetric Costs
CGT-Baja	$ 734,873	$ 1,560,296	$ 1,484,058	$ 1,140,483	$ 949,651	$ 883,281	$ 861,566	$ 557,735	$ 402,486	$ 214,398	$ 522,102	$ 634,529	$ 9,945,458
CGT City gate	-	-	-	-	-	-	-	-	-	-	-	-	-
CGT-Redwood	826,452	809,891	794,151	710,380	863,690	1,112,484	782,188	660,496	649,722	649,431	632,331	790,267	9,281,483
EPNG-Basin	171,365	177,517	167,121	151,282	182,943	173,452	136,386	55,413	63,917	23,811	75,883	123,906	1,502,996
NGTL-AECO/NIT	-	-	-	-	6,804	44,095	-	-	30,738	39,684	29,448	3,779	154,548
GTNC-All	206,061	214,107	216,817	196,342	219,247	212,736	192,179	191,610	175,607	178,089	167,689	218,577	2,389,061
TW Basin	45,585	89,818	89,724	81,663	59,271	56,102	60,033	52,006	27,762	20,451	21,285	26,096	629,796
Total Transport Cost:	$ 1,984,336	$ 2,851,629	$ 2,751,871	$ 2,280,150	$ 2,281,606	$ 2,482,150	$ 2,032,352	$ 1,517,260	$ 1,350,232	$ 1,125,864	$ 1,448,738	$ 1,797,154	$ 23,903,342

Exhibit 3-5A

Pacific Gas and Electric Company
Reconciliation of Demand Charges and Capacity Release
CPIM Year 17
November 1, 2009 through October 31, 2010

Pipeline:	Demand Charges	Capacity Release Revenue	Discounted (Premium) Capacity Release	Reservation Charge Discount	Refund Adjustments	Other Cost Adjustments (1)	TOTAL
Canadian							
Foothills Pipelines, Ltd.	$ 16,484,007	$ (1,148,711)	$ 820,084				$ 16,155,380
NOVA Gas Transmission	41,657,159	(2,908,791)	712,365				39,460,733
Sub-Total:							55,616,113
Interstate							
El Paso	$ 21,765,311	$ (963,006)		$ (302,680)	$ (1,820,992)		$ 18,678,633
Lodi Gas Storage	900,000	0		0		9,000	909,000
Gas Transmission Northwest	71,289,011	(832,176)					70,456,835
Transwestern Pipeline	19,918,746	(1,285,145)		(131,908)			18,501,693
Kern River	0	0	0	0	(8,392)		(8,392)
Sub-Total:							108,537,769
Intrastate							
California Gas Transmission	$ 58,783,965	$ (7,897,502)	$ (154,857)				$ 50,731,606
Firm Core Storage	40694513						40694513
Incremental Core Storage	800004						800004
Sub-Total:							92226123
Annual Total:	$ 272,292,716	$ (15,035,331)	$ 1,377,592	$ (434,588)	$ (1,829,384)	$ 9,000	$ 256,380,005

(1) Other Cost Adjustments = Injection/Withdrawal Charges

Exhibit 3-6A

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 17
November 1, 2009 through October 31, 2010

El Paso Natural Gas Co.

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 201,774.00	$ 30.00	6,053,220	0	6,053,220	5,718,192	94.47%
Dec-09	266,774.00	31.00	6,254,994	0	6,254,994	6,037,985	96.53%
Jan-10	266,774.00	31.00	6,254,994	0	6,254,994	5,684,386	90.88%
Feb-10	266,774.00	28.00	5,649,672	0	5,649,672	5,145,646	91.08%
Mar-10	201,774.00	31.00	6,254,994	0	6,254,994	6,222,562	99.48%
Apr-10	201,774.00	30.00	6,053,220	0	6,053,220	5,899,726	97.46%
May-10	201,774.00	31.00	6,254,994	0	6,254,994	5,981,867	95.63%
Jun-10	201,774.00	30.00	6,053,220	(2,550,000)	3,503,220	2,430,417	69.38%
Jul-10	201,774.00	31.00	6,254,994	(1,240,000)	5,014,994	2,803,404	55.90%
Aug-10	201,774.00	31.00	6,254,994	(3,720,000)	2,534,994	1,044,347	41.20%
Sep-10	201,774.00	30.00	6,053,220	(2,700,000)	3,353,220	3,328,205	99.25%
Oct-10	201,774.00	31.00	6,254,994	(775,000)	5,479,994	5,434,458	99.17%
Totals:			73,647,510	(10,985,000)	62,662,510	55,731,195	88.94%

Transwestern Pipeline Company

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 150,000.00	$ 30.00	4,500,000	(900,000)	3,600,000	3,506,542	97.40%
Dec-09	226,720.00	31.00	7,028,320	0	7,028,320	6,909,105	98.30%
Jan-10	226,720.00	31.00	7,028,320	0	7,028,320	6,901,818	98.20%
Feb-10	226,720.00	28.00	6,348,160	0	6,348,160	6,281,773	98.95%
Mar-10	150,000.00	31.00	4,650,000	0	4,650,000	4,559,334	98.05%
Apr-10	150,000.00	30.00	4,500,000	0	4,500,000	4,315,529	95.90%
May-10	150,000.00	31.00	4,650,000	0	4,650,000	4,617,957	99.31%
Jun-10	150,000.00	30.00	4,500,000	(450,000)	4,050,000	4,000,496	98.78%
Jul-10	150,000.00	31.00	4,650,000	(2,325,000)	2,325,000	2,135,561	91.85%
Aug-10	150,000.00	31.00	4,650,000	(2,945,000)	1,705,000	1,573,180	92.27%
Sep-10	150,000.00	30.00	4,500,000	(2,850,000)	1,650,000	1,637,309	99.23%
Oct-10	150,000.00	31.00	4,650,000	(2,635,000)	2,015,000	2,007,357	99.62%
Totals:			61,654,800	(12,105,000)	49,549,800	48,445,960	97.77%

Exhibit 3-6B

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 17
November 1, 2009 through October 31, 2010

Gas Transmission Northwest Corporation

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 609,968.00	$ 30.00	18,299,040	(600,000)	17,699,040	17,607,597	99.48%
Dec-09	609,968.00	31.00	18,909,008	-	18,909,008	17,976,694	95.07%
Jan-10	609,968.00	31.00	18,909,008	-	18,909,008	18,436,183	97.50%
Feb-10	609,968.00	28.00	17,079,104	-	17,079,104	16,755,197	98.10%
Mar-10	609,968.00	31.00	18,909,008	-	18,909,008	18,723,981	99.02%
Apr-10	609,968.00	30.00	18,299,040	-	18,299,040	18,183,575	99.37%
May-10	609,968.00	31.00	18,909,008	(930,000)	17,979,008	16,426,466	91.36%
Jun-10	609,968.00	30.00	18,299,040	(1,800,000)	16,499,040	16,377,842	99.27%
Jul-10	609,968.00	31.00	18,909,008	(3,695,500)	15,213,508	15,009,952	98.66%
Aug-10	609,968.00	31.00	18,909,008	(3,425,500)	15,483,508	15,222,143	98.31%
Sep-10	609,968.00	30.00	18,299,040	(3,315,000)	14,984,040	14,333,198	95.66%
Oct-10	609,968.00	31.00	18,909,008	-	18,909,008	18,773,248	99.28%
Totals:			222,638,320	(13,766,000)	208,872,320	203,826,076	97.58%

California Gas Transmission-Baja Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 348,000.00	$ 30.00	10,440,000	(1,800,510)	8,639,490	8,220,054	95.15%
Dec-09	669,000.00	31.00	20,739,000	(4,229,981)	16,509,019	16,044,944	97.19%
Jan-10	669,000.00	31.00	20,739,000	(995,627)	19,743,373	14,904,114	75.49%
Feb-10	669,000.00	28.00	18,732,000	(1,677,144)	17,054,856	11,398,429	66.83%
Mar-10	348,000.00	31.00	10,788,000	-	10,788,000	10,730,516	99.47%
Apr-10	348,000.00	30.00	10,440,000	(209,880)	10,230,120	9,980,577	97.56%
May-10	348,000.00	31.00	10,788,000	(753,827)	10,034,173	9,735,209	97.02%
Jun-10	348,000.00	30.00	10,440,000	(3,112,950)	7,327,050	6,302,088	86.01%
Jul-10	348,000.00	31.00	10,788,000	(3,565,000)	7,223,000	4,547,867	62.96%
Aug-10	348,000.00	31.00	10,788,000	(6,665,000)	4,123,000	2,422,578	58.76%
Sep-10	348,000.00	30.00	10,440,000	(4,500,000)	5,940,000	5,899,462	99.32%
Oct-10	348,000.00	31.00	10,788,000	(3,564,566)	7,223,434	7,169,816	99.26%
Totals:			155,910,000	(31,074,485)	124,835,515	107,355,654	86.00%

Exhibit 3-6B

Pacific Gas and Electric
Core Gas Supply - Capacity Utilization
CPIM Year 17
November 1, 2009 through October 31, 2010

California Gas Transmission- Redwood Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 608,766.00	$ 30.00	18,262,980	(1,539,840)	16,723,140	16,843,956	100.72%
Dec-09	608,766.00	31.00	18,871,746	(1,618,944)	17,252,802	17,303,284	100.29%
Jan-10	608,766.00	31.00	18,871,746	(1,417,816)	17,453,930	17,453,858	100.00%
Feb-10	608,766.00	28.00	17,045,448	(1,432,536)	15,612,912	15,612,755	100.00%
Mar-10	608,766.00	31.00	18,871,746	(1,368,805)	17,502,941	17,672,246	100.97%
Apr-10	608,766.00	30.00	18,262,980	(1,604,640)	16,658,340	17,663,241	106.03%
May-10	608,766.00	31.00	18,871,746	(3,858,353)	15,013,393	15,294,228	101.87%
Jun-10	608,766.00	30.00	18,262,980	(3,746,550)	14,516,430	14,516,392	100.00%
Jul-10	608,766.00	31.00	18,871,746	(4,584,838)	14,286,908	14,279,589	99.95%
Aug-10	608,766.00	31.00	18,871,746	(4,598,199)	14,273,547	14,273,219	100.00%
Sep-10	608,766.00	30.00	18,262,980	(4,469,550)	13,793,430	13,806,836	100.10%
Oct-10	608,766.00	31.00	18,871,746	(1,945,870)	16,925,876	16,982,871	100.34%
Totals:			222,199,590	(32,185,941)	190,013,649	191,702,475	100.89%

California Gas Transmission-Silverado Path

Month/ Year	Daily Volume	Days in Month	Contract Capacity	Capacity Release	Net Contract Capacity	Gas Received at CityGate	Percent of Utilization
Nov-09	$ 1,000.00	$ 30.00	30,000	(30,000)	-	-	100.00%
Dec-09	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Jan-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Feb-10	1,000.00	28.00	28,000	(28,000)	-	-	100.00%
Mar-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Apr-10	1,000.00	30.00	30,000	(30,000)	-	-	100.00%
May-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Jun-10	1,000.00	30.00	30,000	(30,000)	-	-	100.00%
Jul-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Aug-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Sep-10	1,000.00	30.00	30,000	(30,000)	-	-	100.00%
Oct-10	1,000.00	31.00	31,000	(31,000)	-	-	100.00%
Totals:			365,000	(365,000)	-	-	100.00%

Footnote: (1) Includes any capacity assigned to Core Transport Agent (CTA) as well as releases to other parties.
(2) Utilization may reflect interruptible transportation which can result in a % above 100%.

Exhibit 3-6B

Pacific Gas and Electric
Management of Firm Storage Inventory
CPIM Year 17
November 1, 2009 through October 31, 2010

Predetermined Storage

Month/Year	Natural Gas Nominations (MMBtus)	Inventory Adjustments (MMBtus)	EOM Inventory Level
Beginning Inventory As of 10/31/2009			**31,122,862**
Nov-09	(2,334,517)	-	28,788,345
Dec-09	(9,794,000)	(209,295)	18,785,050
Jan-10	(10,544,000)	(889,187)	7,351,863
Feb-10	(5,011,000)	-	2,340,863
Mar-10	(1,798,896)	-	541,967
Apr-10	4,976,984	-	5,518,951
May-10	5,180,333	83,563	10,782,847
Jun-10	4,725,000	353,826	15,861,673
Jul-10	4,430,000	-	20,291,673
Aug-10	4,058,000	-	24,349,673
Sep-10	3,645,000	111,803	28,106,476
Oct-10	2,799,000	-	30,905,476
			30,905,476
			30,905,476
EOY Inventory:	331,904	(549,290)	**30,688,090**

Pacific Gas and Electric
Management of Incremental Storage Inventory
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/Year	Natural Gas Nominations (MMBtus)	Inventory Adjustments (MMBtus)	EOM Inventory Level (MMBtus)
	CGT and Lodi Gas Storage		
Nov-09	1,000,000	-	1,000,000
Dec-09	1,050,000	(250,000)	1,800,000
Jan-10	800,000	(249,999)	2,350,001
Feb-10	550,001	(250,001)	2,650,001
Mar-10	300,000	(250,000)	2,700,001
Apr-10	125,000	-	2,825,001
May-10	78,275	-	2,903,276
Jun-10	277,500	-	3,180,776
Jul-10	355,000	-	3,535,776
Aug-10	932,500	-	4,468,276
Sep-10	1,000,000	-	5,468,276
Oct-10	1,000,000	-	6,468,276
EOY Inventory:	7,468,276	(1,000,000)	12,936,552

Pacific Gas Electric Company
Fixed Transportation and Storage Costs
CPIM Year 17
November 1, 2009 through October 31, 2010

	Canadian Pipelines				U S Interstate Pipelines						CA Intrastate Pipelines					CA Intrastate Storage					
Month/ Year	Foothills Pipelines	Nova Gas Transmission Ltd.	Sub-Total	%	Gas Transmission NW	EPNG Pipeline	Kern River Gas	Transwestern Pipeline	Sub-Total	%	CGT - Baja	CGT Redwood	CGT Silverado	Sub-Total	%	CGT Firm Contracts	CGT Incremental Contracts	Lodi Contracts	Sub-Total	Total	%
Nov-09	$ 965,673	$ 3,006,280	$ 3,971,953	**7%**	$ 5,859,371	$ 1,771,387		$ 1,350,000	$ 8,980,758	**8%**	$ 2,249,571	$ 1,873,939	$ 3,115	$ 4,126,625.00	**7%**	$ 3,398,617	$ 66,667	$ 75,000	$ 3,540,284.00	$ 20,619,620.00	**8%**
Dec-09	974,669	3,034,285	4,008,954	**7%**	6,054,683	1,766,618		1,868,060	9,689,361	**9%**	4,858,406	1,870,927	3,115	6,732,448.00	**11%**	3,398,617	66,667	76,500	3,541,784.00	23,972,547.00	**9%**
Jan-10	1,399,856	3,516,662	4,916,518	**8%**	6,054,683	1,771,388		1,870,664	9,696,735	**9%**	5,050,236	1,874,327	3,084	6,927,647.00	**12%**	3,381,478	66,667	75,000	3,523,145.00	25,064,045.00	**9%**
Feb-10	1,414,991	3,513,185	4,928,176	**8%**	5,468,746	1,771,388		1,689,632	8,929,766	**8%**	5,065,777	1,856,264	3,084	6,925,125.00	**12%**	3,382,542	66,667	75,500	3,524,709.00	24,307,776.00	**9%**
Mar-10	1,458,609	3,621,481	5,080,090	**9%**	6,054,683	1,771,388	(8,392)	1,395,000	9,212,679	**8%**	2,437,288	1,879,590	3,084	4,319,962.00	**7%**	3,382,542	66,667	77,500	3,526,709.00	22,139,440.00	**8%**
Apr-10	1,475,115	3,662,462	5,137,577	**9%**	5,859,371	1,699,388	-	1,646,550	9,205,309	**8%**	2,388,290	1,848,520	3,084	4,239,894.00	**7%**	3,387,601	66,667	75,750	3,530,018.00	22,112,798.00	**8%**
May-10	1,404,236	3,486,481	4,890,717	**8%**	6,054,683	1,771,388	-	1,701,435	9,527,506	**9%**	2,266,979	1,845,275	3,084	4,115,338.00	**7%**	3,387,601	66,667	75,775	3,530,043.00	22,063,604.00	**8%**
Jun-10	1,423,959	3,535,451	4,959,410	**9%**	5,859,371	1,755,236	-	1,646,550	9,261,157	**8%**	2,409,448	1,843,870	3,084	4,256,402.00	**7%**	3,387,601	66,667	75,750	3,530,018.00	22,006,987.00	**8%**
Jul-10	1,494,228	3,576,210	5,070,438	**9%**	6,054,683	1,905,107	-	1,701,435	9,661,225	**9%**	2,437,288	1,867,130	3,084	4,307,502.00	**7%**	3,387,601	66,667	75,775	3,530,043.00	22,569,208.00	**8%**
Aug-10	1,459,890	3,494,026	4,953,916	**9%**	6,054,683	978,027	-	1,701,435	8,734,145	**8%**	2,437,288	1,865,695	3,084	4,306,067.00	**7%**	3,387,601	66,667	75,775	3,530,043.00	21,524,171.00	**8%**
Sep-10	1,501,059	3,592,558	5,093,617	**9%**	5,859,371	1,077,897	-	1,646,550	8,583,818	**8%**	2,437,288	1,863,511	3,084	4,303,883.00	**7%**	3,406,356	66,667	75,675	3,548,698.00	21,530,016.00	**8%**
Oct-10	1,511,722	3,618,078	5,129,800	**9%**	6,054,683	1,905,107		1,701,435	9,661,225	**9%**	2,402,367	1,817,621	3,084	4,223,072.00	**7%**	3,406,356	66,667	75,000	3,548,023.00	22,562,120.00	**8%**
Totals:	$ 16,484,007	$ 41,657,159	$ 58,141,166	**100%**	$ 71,289,011	$ 19,944,319	$ (8,392)	$ 19,918,746	$ 111,143,684	**100%**	$ 36,440,226	$ 22,306,669	$ 37,070	$ 58,783,965.00	**100%**	$ 40,694,513	$ 800,004	$ 909,000	$ 42,403,517.00	$ 270,472,332.00	**100%**

Pacific Gas and Electric Company
Summary of Firm Storage Injections and Withdrawals
CPIM Year 17
November 1, 2009 through October 31, 2010

	PG&E Firm Storage						CGT Incremental Storage		
Month/ Year	**Injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**	**Injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**	**Injections**	**Withdrawals**	**Total Physical Inventory (MMBtus)**
Beginning Balance:			**31,122,862**			**500,000**			**500,000**
Nov-09	(2,334,517)		28,788,345	0	0	500,000	0	-	500,000
Dec-09	(9,794,000)	(209,295)	18,785,050	(50,000)	0	450,000	(150,000)	-	350,000
Jan-10	(10,544,000)	(889,187)	7,351,863	(249,999)	0	200,001	0	-	350,000
Feb-10	(5,011,000)		2,340,863	(200,001)	0	0	(50,000)	-	300,000
Mar-10	(1,798,896)		541,967	0	0	0	(250,000)	-	50,000
Apr-10	4,976,984		5,518,951	0	0	0	75,000	-	125,000
May-10	5,180,333	83,563	10,782,847	0	0	0	77,500	-	202,500
Jun-10	4,725,000	353,826	15,861,673	0	0	0	75,000	-	277,500
Jul-10	4,430,000		20,291,673	0	0	0	77,500	-	355,000
Aug-10	4,058,000		24,349,673	500,000	0	500,000	77,500	-	432,500
Sep-10	3,645,000	111,803	28,106,476	0	0	500,000	67,500	-	500,000
Oct-10	2,799,000		30,905,476	0	0	500,000	0	-	500,000
Ending Balance:	331,904	(549,290)	30,905,476	0	0	500,000	-		500,000

Exhibit 3-7D

Table II
Pacific Gas and Electric Company
CPIM Performance
CPIM Year 17
November 1, 2009 through October 31, 2010

	Interstate and California Gas Purchases			Pipeline Charges		Total CPIM Performance					
Month Year	**Commodity (1) Actuals**	**Commodity (1) Benchmark**	**Benchmark Less Actuals (Over) Under**	**Actuals (2)**	**Benchmark (3)**	**Actuals**	**Benchmark**	**Benchmark Less Actuals (Over) Under**	**Deadband Upper Limit (4)**	**Deadband Lower Limit (5)**	**(Over)/Under Deadband**
Nov-09	$107,944,949	$112,717,408	$4,772,459	$19,939,840	$20,619,619	$127,884,789	$133,337,027	$5,452,238	$135,591,375	$132,209,853	$4,325,064
Dec-09	$157,052,676	$155,620,615	($1,432,061)	$22,821,178	$23,972,546	$179,873,854	$179,593,161	($280,693)	$182,705,573	$178,036,955	(1,836,899)
Jan-10	$161,191,724	$157,492,102	($3,699,622)	$24,841,126	$25,064,044	$186,032,850	$182,556,146	($3,476,704)	$185,705,988	$180,981,225	(5,051,625)
Feb-10	$124,086,091	$126,510,462	$2,424,371	$24,095,402	$24,307,776	$148,181,493	$150,818,238	$2,636,745	$153,348,447	$149,553,133	1,371,640
Mar-10	$127,933,010	$129,948,888	$2,015,878	$22,085,050	$22,139,440	$150,018,060	$152,088,328	$2,070,268	$154,687,306	$150,788,839	770,779
Apr-10	$115,071,556	$118,349,264	$3,277,708	$22,077,848	$22,112,798	$137,149,404	$140,462,062	$3,312,658	$142,829,047	$139,278,569	2,129,165
May-10	$84,999,140	$86,040,845	$1,041,705	$20,992,889	$22,063,603	$105,992,029	$108,104,448	$2,112,419	$109,825,265	$107,244,040	1,252,011
Jun-10	$63,031,585	$65,285,656	$2,254,071	$20,171,139	$22,006,986	$83,202,724	$87,292,642	$4,089,918	$88,598,355	$86,639,785	3,437,061
Jul-10	$68,159,671	$70,219,394	$2,059,723	$20,091,326	$22,569,208	$88,250,997	$92,788,602	$4,537,605	$94,192,990	$92,086,408	3,835,411
Aug-10	$66,599,997	$67,669,431	$1,069,434	$18,643,488	$21,524,171	$85,243,485	$89,193,602	$3,950,117	$90,546,991	$88,516,908	3,273,423
Sep-10	$53,383,651	$54,642,318	$1,258,667	$19,087,546	$21,530,015	$72,471,197	$76,172,333	$3,701,136	$77,265,179	$75,625,910	3,154,713
Oct-10	$61,275,353	$65,719,031	$4,443,678	$21,533,167	$22,562,120	$82,808,520	$88,281,151	$5,472,631	$89,595,532	$87,623,961	4,815,441
Totals	$1,190,729,403	$1,210,215,414	$19,486,011	$256,379,999	$270,472,326	$1,447,109,402	$1,480,687,740	$33,578,338	$1,504,892,048	$1,468,585,586	$ 21,476,184

CPIM Shareholder Reward: $ 4,295,237

Footnotes:

(1) Commodity costs consist of Canadian and U.S. natural gas purchases and PG&E's CityGate volumetric transportation costs.
(2) Includes intrastate, interstate and Canadian pipeline reservation charges net of capacity release revenue.
(3) Benchmark is based on fixed transportation and storage costs.
(4) "Upper Limit" equal Benchmark +2.0 % of Commodity benchmark
(5) "Lower Limit" equal Benchmark - 1.0% of Commodity Benchmark.

Exhibit 3-8A

Pacific Gas and Electric
City-Gate Indices
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	California Topock (Firm)	Kingsgate	San Juan	AECO	NGI Daily PG&E CityGate
Nov-09	4.67	5.12	4.53	4.88	4.27
Dec-09	4.79	5.05	4.55	4.81	6.30
Jan-10	6.08	5.69	6.05	5.39	6.21
Feb-10	5.63	5.82	5.63	5.52	5.17
Mar-10	4.98	5.57	4.93	5.26	4.79
Apr-10	4.17	4.55	4.02	4.24	4.47
May-10	4.19	4.03	4.05	3.73	4.31
Jun-10	3.99	4.13	3.94	3.83	4.55
Jul-10	4.68	4.57	4.55	4.26	4.30
Aug-10	4.41	4.06	4.33	3.75	3.95
Sep-10	3.58	3.78	3.45	3.47	4.05
Oct-10	3.92	3.99	3.80	3.68	3.86

Exhibit 3-8B

Pacific Gas and Electric
Schedule of Miscellaneous Costs and Revenues
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	Broker Fees	Reservation Fees	Cochrane Extraction Revenue	OFO Charges	Parking & Lending Charges	Total Misc Charges
Nov-09	$ 12,346.00	$ 300,000.00	$ (1,088,227.00)	$ 4,653.00	$ -	($771,228)
Dec-09	11,854.00	-	(1,142,200.00)	(4,653.00)	-	($1,134,999)
Jan-10	14,567.00	-	(1,216,958.00)	-	-	($1,202,391)
Feb-10	21,199.00	-	(1,090,247.00)	-	-	($1,069,048)
Mar-10	16,737.00		(1,176,324.00)		2,500.00	($1,157,087)
Apr-10	17,705.00	-	(1,125,672.00)	-	-	($1,107,967)
May-10	28,700.00	-	(1,054,072.00)	-	3,000.00	($1,022,372)
Jun-10	21,796.00	-	(1,111,902.00)	-	-	($1,090,106)
Jul-10	14,048.00	-	(765,955.00)	-	-	($751,907)
Aug-10	17,216.00	-	(843,902.00)	-	-	($826,686)
Sep-10	19,480.00	-	(439,206.00)	-	-	($419,726)
Oct-10	17,598.00	-	(1,261,786.00)	-	-	($1,244,188)
Totals:	$ 213,246.00	$ 300,000.00	$ (12,316,451.00)	$ -	$ 5,500.00	($11,797,705)

Exhibit 3-8C

Pacific Gas and Electric Company
Modified Determined Usage
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	Burner Tip Modified Determined Therm Usage	Burner Tip Modified Determined Gross-Up	Modified Determined Converted to MMBtus	Operating Imbalance Adjustment (MMBtus)	Firm Storage (CGT) Injection/ (Withdrawal)	Incremental Storage Injection/ (Withdrawal) (MMBtu)	Benchmark Load at CityGate (MMBtu)
	a	b	c	d	e	f	g
		(a) x 1+.033)					(c.) +(d)+(e)+(f)=(g)
Nov-09	248,686,863	256,147,466	25,614,748	347,106	(2,178,173)	-	23,783,681
Dec-09	417,339,704	429,859,892	42,985,991	371,100	(10,582,219)	(200,000)	32,574,872
Jan-10	376,503,198	387,798,295	38,779,834	356,196	(11,147,324)	(249,999)	27,738,707
Feb-10	266,434,535	274,427,573	27,442,759	341,648	(4,803,437)	(250,001)	22,730,969
Mar-10	262,168,322	270,033,372	27,003,339	312,363	(1,867,669)	(250,000)	25,198,033
Apr-10	217,020,921	223,531,551	22,353,155	176,581	5,607,612	75,750	28,213,098
May-10	162,962,552	167,851,429	16,785,143	156,992	5,326,529	78,275	22,346,939
Jun-10	115,645,088	119,114,441	11,911,445	160,886	4,736,254	75,750	16,884,335
Jul-10	111,776,157	115,129,443	11,512,947	165,070	4,499,207	78,275	16,255,499
Aug-10	122,640,354	126,319,565	12,631,956	189,534	4,121,618	583,845	17,526,953
Sep-10	113,829,441	117,244,326	11,724,432	200,200	3,742,804	68,175	15,735,611
Oct-10	140,155,430	144,360,091	14,436,011	204,998	3,102,146	-	17,743,155
Totals:	2,555,162,565	2,634,372,605	263,437,264	2,982,674	557,348	460,069	267,437,355

Exhibit 3-8D

SB_GT&S_0434637

Pacific Gas and Electric
Review of Southwest and CA Index at CityGate
CPIM Year 17
November 1, 2009 through December 31, 2010

Month/ Year	Southwest & CA Index	CGT Shrinkage Rate	Index Gross-Up to CityGate (a/(1-b)	Baja CGT Volumetric Rate	Southwest & CA Index at CityGate (c+d)
	a	b	c	d	f
Nov-09	4.52	1.40%	4.584178	0.0894	4.673578
Dec-09	4.63	1.40%	4.695740	0.0894	4.785140
Jan-10	5.91	1.40%	5.993915	0.0885	6.082415
Feb-10	5.46	1.40%	5.537525	0.0885	5.626025
Mar-10	4.82	1.40%	4.888438	0.0885	4.976938
Apr-10	4.02	1.40%	4.077079	0.0885	4.165579
May-10	4.04	1.40%	4.097363	0.0885	4.185863
Jun-10	3.85	1.40%	3.904665	0.0885	3.993165
Jul-10	4.53	1.40%	4.594320	0.0885	4.682820
Aug-10	4.26	1.40%	4.320487	0.0885	4.408987
Sep-10	3.44	1.40%	3.488844	0.0885	3.577344
Oct-10	3.78	1.40%	3.833671	0.0885	3.922171

Exhibit 3-8E

Pacific Gas and Electric
Review of Malin Index (AECO)
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	AECO Index (Can$/GJ) (1)	Conversion of AECO Index (Can$/MMBtu) (2)	Foothills Fuel %	Gross-up AECO Index Gross-Up (c/1-d)	Monthly Exchange Rate (3)	AECO-Kingsgate Index (e/f)	GTNC Fuel Rate %	Gross-up KingsGate Index (g/(1-h)	GTNC Volumetric Rate	Total Malin Index (i+j)	CGT Fuel %	Malin Index Gross-Up (k/(1-l)	Redwood CGT Volumetric Rate	Total CityGate Malin Index (m+n)
a	b	c	d	e	f	g	h	i	j	k	l	m	n	o
Nov-09	4.640800	4.896304	0.0099730	4.945627	1.058582	4.6719353	0.017148880	4.7534517	0.01169936	4.7651510	0.0140	4.832810	0.0459	4.878710
Dec-09	4.527600	4.776872	0.0130500	4.840034	1.048812	4.6147775	0.015311500	4.6865354	0.01169936	4.6982347	0.0140	4.764944	0.0459	4.8108439
Jan-10	5.156400	5.440291	0.0110340	5.500989	1.064169	5.1692811	0.016536420	5.2561998	0.01169936	5.2678992	0.0140	5.342697	0.0455	5.3881969
Feb-10	5.234300	5.522480	0.0099730	5.578110	1.052787	5.2984223	0.016536420	5.3875125	0.01169936	5.3992118	0.0140	5.475874	0.0455	5.5213741
Mar-10	4.849400	5.116389	0.0090190	5.162953	1.021304	5.0552561	0.014086580	5.1274848	0.01169936	5.1391842	0.0140	5.212154	0.0455	5.2576543
Apr-10	3.837600	4.048883	0.0090190	4.085732	1.009877	4.0457720	0.018986260	4.1240728	0.01169936	4.1357721	0.0140	4.194495	0.0455	4.2399950
May-10	3.535600	3.730256	0.0099730	3.767833	1.060850	3.5517110	0.019598720	3.6227115	0.01169936	3.6344108	0.0140	3.686015	0.0455	3.7315151
Jun-10	3.600000	3.798202	0.0099730	3.836463	1.046156	3.6671994	0.013474120	3.7172866	0.01169936	3.7289859	0.0140	3.781933	0.0455	3.8274330
Jul-10	3.910300	4.125585	0.0110340	4.171615	1.034233	4.0335351	0.025723320	4.1400304	0.01169936	4.1517298	0.0140	4.210679	0.0455	4.2561793
Aug-10	3.507300	3.700398	0.0119890	3.745300	1.058560	3.5381087	0.028785620	3.6429739	0.01169936	3.6546733	0.0140	3.706565	0.0455	3.7520652
Sep-10	3.149600	3.323004	0.0110340	3.360079	1.029527	3.2637119	0.028785620	3.3604443	0.01169936	3.3721437	0.0140	3.420024	0.0455	3.4655240
Oct-10	3.377000	3.562924	0.0110340	3.602676	1.022265	3.5242095	0.012249200	3.5679136	0.01169936	3.5796130	0.0140	3.630439	0.0455	3.6759391

Footnotes:
(1) AECO Index (Canadian Enerdata 30-day baseload Index at AECO C).
(b) A conversation rate of 1.055056 is used.
(f) This is the Canadian exchange rate at date of settlement.

Exhibit 3-8F

Pacific Gas and Electric
Review of San Juan Index
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	San Juan Index $/MMBtu (1)	TW Contract Fuel %	Gross-Up of San Juan Index (b/(1-c))	TW Volumetric Rate	Gross-Up of San Juan Index to Topock (d+e)	CGT Fuel %	Gross-Up of San Juan Index (f/(1-g))	CGT-Baja Volumetric Rate	Total CityGate Index (h+i)
a	b	c	d	e	f	g	h	i	j
Nov-09	4.260	0.0245	4.3669913	0.0130	4.37999129	0.014	$ 4.44	$ 0.09	4.531582
Dec-09	4.280	0.0245	4.3874936	0.0130	4.40049359	0.014	4.46	0.09	4.552375
Jan-10	5.720	0.0245	5.8636597	0.0130	5.87665966	0.014	5.96	0.09	6.048601
Feb-10	5.320	0.0245	5.4536135	0.0130	5.46661353	0.014	5.54	0.09	5.632733
Mar-10	4.640	0.0245	4.7565351	0.0130	4.76953511	0.014	4.84	0.09	4.925757
Apr-10	3.770	0.0245	3.8646848	0.0130	3.87768478	0.014	3.93	0.09	4.021243
May-10	3.800	0.0245	3.8954382	0.0130	3.90843824	0.014	3.96	0.09	4.052433
Jun-10	3.690	0.0245	3.7826756	0.0130	3.79567555	0.014	3.85	0.09	3.938070
Jul-10	4.280	0.0245	4.3874936	0.0130	4.40049359	0.014	4.46	0.09	4.551475
Aug-10	4.070	0.0245	4.1722194	0.0130	4.18521937	0.014	4.24	0.09	4.333144
Sep-10	3.220	0.0245	3.3008713	0.0130	3.31387135	0.014	3.36	0.09	3.449424
Oct-10	3.560	0.0245	3.6494106	0.0130	3.66241056	0.014	3.71	0.09	3.802912

Pacific Gas and Electric
Review of Kingsgate Index
CPIM Year 17
November 1, 2009 through October 31, 2010

Month/ Year	Kingsgate Index (US $/MMBtu) (1)	GTNC Fuel %	Gross-Up of Kingsgate Index (b/(1-c)	GTNC Volumetric Rate	Total Index at Malin	CGT Fuel %	Gross-Up of Malin Index (f/(1-g)	Redwood CGT Volumetric Rate	Total CityGate Index (h+i)
a	b	c	d	e	f	g	h	i	j
Nov-09	4.906168	0.017149	4.9917713	0.01169936	5.00347065	0.0140	5.074514	0.0459	$ 5.120414
Dec-09	4.851750	0.015312	4.9271927	0.01169936	4.93889207	0.0140	5.009018	0.0459	5.054918
Jan-10	5.457138	0.016536	5.5488969	0.01169936	5.56059625	0.0140	5.639550	0.0455	5.685050
Feb-10	5.589173	0.016536	5.6831520	0.01169936	5.69485135	0.0140	5.775711	0.0455	5.821211
Mar-10	5.354761	0.014087	5.4312690	0.01169936	5.44296837	0.0140	5.520252	0.0455	5.565752
Apr-10	4.348670	0.018986	4.4328329	0.01169936	4.44453228	0.0140	4.507639	0.0455	4.553139
May-10	3.840249	0.019599	3.9170175	0.01169936	3.92871689	0.0140	3.984500	0.0455	4.030000
Jun-10	3.959790	0.013474	4.0138734	0.01169936	4.02557277	0.0140	4.082731	0.0455	4.128231
Jul-10	4.332913	0.025723	4.4473126	0.01169936	4.45901201	0.0140	4.522325	0.0455	4.567825
Aug-10	3.830808	0.028786	3.9443485	0.01169936	3.95604788	0.0140	4.012219	0.0455	4.057719
Sep-10	3.564460	0.028786	3.6701063	0.01169936	3.68180564	0.0140	3.734083	0.0455	3.779583
Oct-10	3.827093	0.012249	3.8745532	0.01169936	3.88625254	0.0140	3.941433	0.0455	3.986933

Footnote:
(1) CGPR NGX AB-NIT Month Ahead Index (7A) C$/GJ + BC System As-Available Rate converted to US$/MMBtu

APPENDIX B
GLOSSARY

Benchmark - Is made up of three components: 1) the fixed transportation cost component, which includes interstate, backbone transmission system, and upstream Canadian capacity reservation costs; 2) the variable cost component, which covers commodity costs, 80% of winter hedging transaction premiums and settlement net gains and losses in the month of related gas flow, and volumetric transportation costs; and 3) a storage cost component.

BTU - Is the amount of heat necessary to raise one pound of water one degree fahrenheit.

City-Gate – A receiving point where gas is delivered to a local distribution company (i.e. investor owned utility).

Core Fixed Cost Account (CFCA) – A regulatory balancing account to record the authorized general rate case distribution base revenue amounts (with credits and adjustments), and other core transportation costs, and transportation revenue from core customers. Any under or over collection of balances will be incorporated into core transportation rates in PG&E's annual gas true-up of balancing accounts.

Core Pipeline Demand Charge Account (CPDCA) – A regulatory balancing account to record the costs associated with backbone transmission, interstate capacity, and Canadian capacity for service to core customers taking procurement service from PG&E. Balances apply to all core rate schedules and contracts subject to the jurisdiction of the CPUC, with exception to specific exclusion by the CPUC.

Core Fixed Cost Account (CFCA) – This account functions as a balancing account recorded in SoCalGas' financial statements. The purpose of this account is to balance the difference between authorized margins, and other non-gas fixed costs allocated to the core market with revenues intended to recover these costs.

Demand Charges – Reservation charges for firm transportation service, which is based on volume. This charge is the price for guaranteed capacity and is paid regardless of throughput.

FERC Order 636- On April 8, 1992, FERC Order required the conversion of pipeline service providers to function primarily as transportation entities. This resulted in pipeline providers to unbundle their services, which created greater competition among gas suppliers and ensure reliable supply at the lowest price.

Firm Access Rights – Is a framework where marketers can confirm access to a pipeline transmission system through a contract. This assures the contract holder "firm" access rights in a particular zone that their gas supply will be delivered.

Hub – A location where natural gas pipelines come together.

Interruptible Service – Seller can interrupt service of transporting gas service if it is required to serve a higher priority customer. The total cost is usually less than firm access rights services. In general, interruptible service contracts can have a term as short as several days to one month.

MMBtu – A million British Thermal Units. It is measurement of gas based on a standard heat value or stored energy.

Nomination – Describes the transportation of a specific quantity of gas from one receipt point to a delivery point. The nomination also identifies the upstream and downstream contracts and/or parties, ranking, and receipt/delivery point.

Over the Counter (OTC) – A security that is not traded on an exchange, usually due to an inability to meet listing requirements. Brokers/dealers negotiate directly with one another over computer networks and by phone, where the NASD monitors their activities.

Park - Gas is held for a set period of time and returned at the same location.

Pipeline Demand Charges - Includes fixed demand and capacity charges from Canadian and FERC regulated interstate pipelines.

Purchase Gas Account (PGA) – A regulatory balancing account to record the cost associated with gas purchased for the PG&E's gas supply portfolio and revenues from the sale of gas, and other amounts specifically authorized by the CPUC. Any balances in the sub-accounts will be incorporated into monthly core procurement rates.

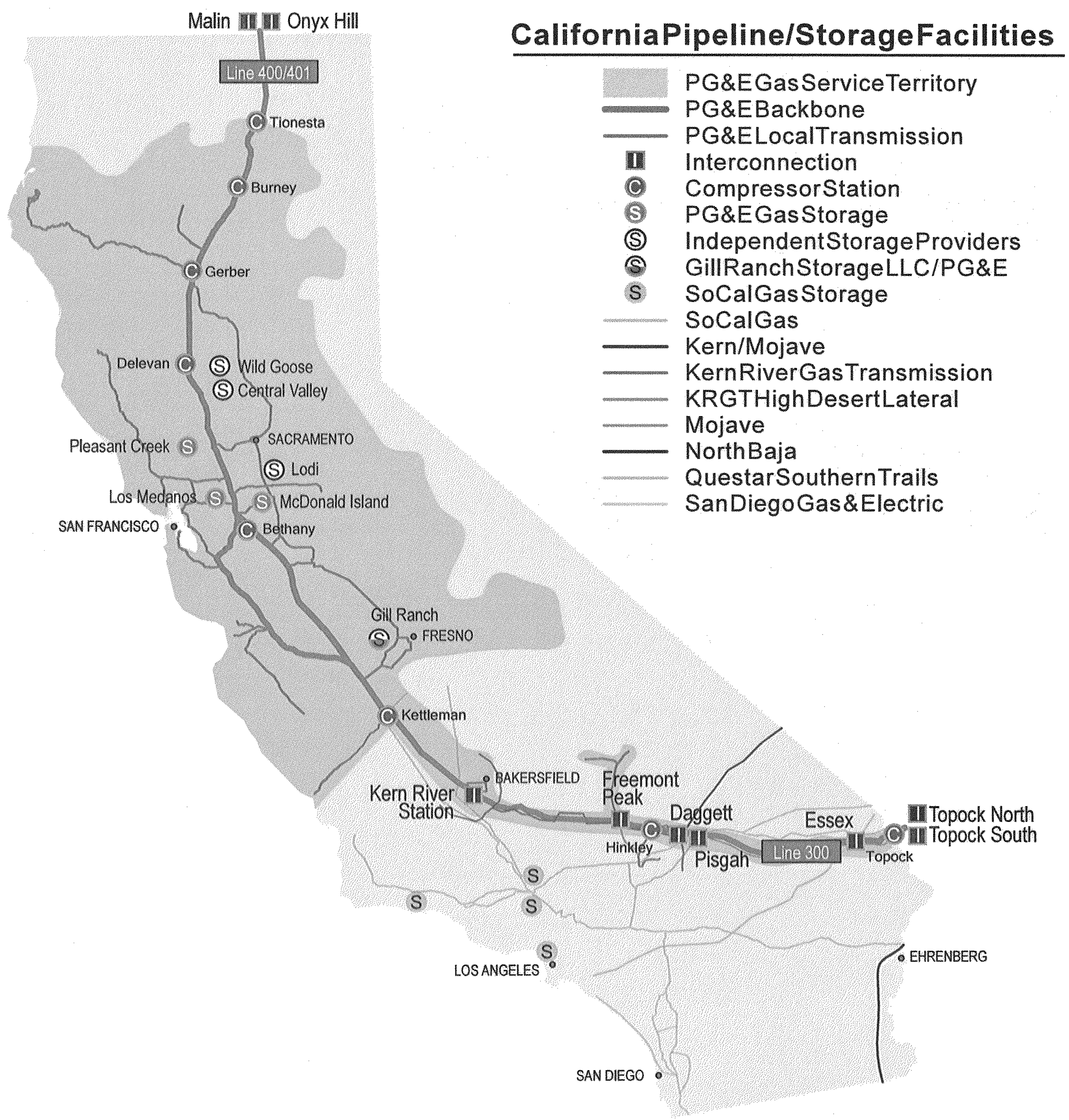
Shrinkage – When natural gas is compressed and transported through an interstate pipeline where it results in volume loss. Each pipeline has a rate regulated by FERC that determines specific shrinkage percentage between delivery points along a pipeline.

Swap – An exchange of streams of payments over time according to specified terms.

Tolerance Band – A CPIM metric which shows a numeric range for the difference between actual costs from the benchmark.

Transportation Charges – Charges for transporting gas from wellheads to the local utility via interstate pipelines. Rates fall under FERC jurisdiction.

Wheeling – Receipt of gas at one location and delivery of gas at another location at a utility's gas system.



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