PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

(Continued)

PRELIMINARY STATEMENT

III. ~~BIENNIAL~~ COST ALLOCATION AND REVENUE REQUIRMENT~~PROCEEDING (BCAP)~~

A. DESCRIPTION AND APPLICABILITY

The ~~Biennial~~ Cost Allocation Proceeding (CAP) is the process by which the utility may request the Commission to review and authorize the following:

1. The level and allocation of the utility's revenue requirement;

2. The reallocation of existing balancing account balances among customer classes; and

3. The establishment of utility rates for core and noncore customers.

~~B~~CAP applies to bills rendered by the utility for natural gas services provided to all customers.

B. APPLICATION~~ AND REVISION DATES~~

1. ~~Beginning in 1991 and for every two years thereafter, t~~The utility shall file an application for revised gas rates for its core and noncore customers in a manner proscribed by the Commission in D.09-XX-XXX, which currently covers the period 2009 through 2011~~ on or prior to March 15 (Application Date) for rates to be effective August 1 (Revision Date).~~. Each filing shall include the following:

   a. A Summary of Forecasted Gas Sales by rate schedule;

   b. A Summary of Commodity Gas Costs by core and noncore;

   c. A Summary of Cost Allocations itemizing procurement and transportation~~transmission~~ costs, allocated from SoCalGas to the utility, and from the utility to core and noncore customers;

   d. A Summary of Revenue Requirements;

   e. A Summary of Revenue Changes from present to proposed rates;

   f. A Summary of Proposed Rates; and

   g. Any workpapers detailing the development of the above summaries.

~~2. The utility may file an advice letter during the interim BCAP period requesting an adjustment to core gas rates. This request shall be filed at least 45 days before the end of the first year of the cost allocation test year. This request shall be limited only to a change in core rates gas rates due to an update of balancing or tracking accounts and shall not change the adopted cost allocation factors nor the sales forecast established in the utility's last BCAP for core customers.~~

(Continued)

PRELIMINARY STATEMENT

III. ~~BIENNIAL~~ COST ALLOCATION AND REVENUE REQUIREMENT ~~PROCEEDING (BCAP)~~

~~B. APPLICATION AND REVISION DATES (CONTINUED)~~

~~2. (Continued)~~

~~a. Core Trigger Filing~~

~~The utility may file an advice letter requesting a core rate adjustment 45 days before the end of the first year of its cost allocation test year if the percentage adjustment to bundled core rates required to amortize the first year's net over or undercollection in the core PGA and core fixed cost accounts over one year of previously adopted core sales would exceed five (5%) percent. The proposed rate filing changes shall be determined as follows:~~

~~(1) The first year of the Forecast Period's net over/under- collection (nine months of recorded data, plus three months of forecasted data) in the core purchased gas account (CPGA) divided by the previously adopted core portfolio gas purchases.~~

~~(2) The first year of the Forecast Period's net over/under- collection (nine months of recorded data, plus three months of forecasted data) in the core gas fixed cost balancing account (CFCA) divided by the previously adopted core transmission volumes.~~

~~(3) The proposed core rates shall equal the sum of the core rate adders computed in (1) and (2) above and the average bundled core rates previously adopted in the utility's last cost allocation proceeding.~~

~~(4) If the sum of the rates computed in (3) above is five percent or greater in absolute value than the previously adopted average bundled core rate, then the utility may file for a change of core rates.~~

C. DEFINITIONS

1. ~~Last General Rate Case (GRC) / Cost of Service (COS) Decision~~

~~The last GRC/COS decision for the utility is Decision 08-07-046, issued by the California Public Utilities Commission on July 31, 2008.~~ T
T

~~2. The Gas OIR Implementation Decision~~

~~The Gas OIR Implementation Decision for the utility is Decision 90-09-089, issued by the California Public Utilities Commission on September 24, 1990, as modified by Decision 90-12-100, dated December 19, 1990, Decision 91-02-022, dated February 6, 1991, Decision 91-02-046, dated February 21, 1991, and Resolution G-2948, dated May 22, 1991.~~ The definitions of principal terms used herein may be found in Rule 1, Definitions.

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PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

~~C. DEFINITIONS (Continued)~~

~~3. Cost of Purchased Gas~~

~~The Cost of Purchased Gas is the sum of expenses included in Accounts 800 through 808 of the Federal Uniform System of Accounts.~~

~~4. Gas Base Margin~~

~~This amount shall be the total annual base revenues authorized by the Commission. The authorized gas margin pursuant to SDG&E Advice Letter 1826-G, effective January 1, 2009, is $243,309,814. The Gas Base Margin represents the total revenue requirement less miscellaneous revenues.~~ T T T

~~5. Cost Allocation Factors~~

~~These percent factors, which are derived from Decision 06-04-033, dated April 13, 2006 are used to allocate recorded gas expenses each month to the appropriate balancing/tracking accounts as follows:~~

	~~Cost Description~~	~~CORE~~	~~NONCORE~~
~~(a)~~	~~Gas Base Margin~~	~~96.26% I~~	~~3.74% R~~

(Continued)

PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

~~C. DEFINITIONS (Continued)~~

~~6. San Diego Franchise Fee Differential (SDFFD)~~

~~A San Diego Franchise Fee Differential of 1.03% is applied to retail customer bills in which utility gas services have been rendered within the corporate limits of the City of San Diego.~~

~~7. San Diego Franchise Fee and Uncollectible Factor (F&U Factor)~~

~~The San Diego Franchise Fee and Uncollectible Factor is 1.023102, based on the Last General Rate Case Decision. This factor is applicable to all retail gas service rendered within the utility's service territory.~~ T

~~8. Balancing Accounts~~

~~Accounts where expenses are compared with revenues from rates designed to recover those expenses; forecasted expenses are compared with recorded expenses; or forecasted revenues are compared with recorded revenues. The resulting over or undercollection, plus interest, as described hereunder, is recorded on the utility's financial statement as an asset or liability, which is owed from or due to the ratepayers. These balances are amortized in future rates, as approved by the Commission.~~

~~9. Memorandum Accounts~~

~~Accounts which operate in the same fashion as the balancing accounts, described above, except that interest would not be accumulated unless approved by the Commission, and stockholders may be at risk for the resulting over or undercollection. These balances are not recorded on the utility's financial statements and do not represent a part of ongoing or future revenue requirements. These balances may be amortized in future rates subject to specific Commission approval.~~

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PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

~~C. DEFINITIONS (Continued)~~

~~10. Transition Costs~~

~~a. As defined in the Decision 87-12-039, transition costs results from a gas purchase contract, tariff, or arrangement which:~~

~~(1) Took effect before the division of the supply portfolio as described in the Decision 87-12-039:~~

~~(2) Was initiated for the benefit of all ratepayers;~~

~~(3) Was intended to be recouped from all ratepayers; and~~

~~(4) Now results in costs in excess of a currently reasonable level.~~

~~b. Costs that have been specifically identified as transition costs by the Commission are:~~

~~(1) Take-or-Pay Costs: Costs allocated to the utility by pipelines for the buy-out or buy-down of pipelines' obligations to take a given amount of gas or prepay the costs of such gas not taken.~~

~~(2) El Paso Liquids Costs: Costs incurred from the direct billing to the utility of El Paso's liquids undercollection.~~

~~(3) Gas Exploration and Development Adjustment (GEDA) Costs: Costs incurred from a program which was initiated to develope new sources of gas supplies.~~

~~(4) FERC Order 94/270 Costs: Commodity-related Costs which were billed directly to the utility.~~

~~(5) Minimum Purchase Obligation (MPO) Excess Gas Costs: Costs estimated to have been in excess of a reasonable amount which would have been paid in a competitive market.~~

~~(6) And other costs which may subsequently be classified by the Commission as transition costs.~~

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PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

~~C. DEFINITIONS (Continued)~~

~~11. Monthly Interest Rate~~

~~Effective July 1, 1985, interest will be at a rate equal to l/12 of the most recently available month's interest rate on Commercial Paper (prime, 3 months), published in the Federal Reserve Statistical Release, G.13, plus 0 basis points or 0.00%. Should publication of the interest rate on Commercial Paper (prime, 3 months) be discontinued, interest will so accrue at a rate equal to l/12 of the most recent month's interest rate on Commercial Paper, plus 0 basis points or 0.00%, which most closely approximates the rate that was discontinued, and which is published in the Federal Reserve Statistical Release, G.13, or its successor publication.~~

~~12. Forecast Period~~

~~The Forecast Period shall be the 24 months commencing with the Revision Dates.~~

~~13. Definition of Terms~~

~~The definitions of principal terms used hereunder are found herein or in Rule 1, Definitions.~~

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III. ~~BIENNIAL~~ COST ALLOCATION AND REVENUE REQUIREMENT ~~PROCEEDING (BCAP)~~

D. REVENUE REQUIREMENT

The Revenue Requirement shall be the sum of all costs estimated to be incurred by the utility for providing gas service to utility customers during the ~~F~~forecast p~~P~~eriod. Utility rates and the allocation of gas service costs to customers shall be established in such a manner as approved by the Commission to recover the costs specified below:

1. Procurement Revenue Requirement

These revenues reflect the commodity cost of gas as described in the Consolidated Gas Portfolio, Section VIII Miscellaneous Accounts of the Preliminary Statement. ~~procured by the utility on behalf of its customers. It equals the sum of:~~

~~a. A forecast of utility gas sales, including forecasted retail noncore and UEG gas purchases from the utility, multiplied by a weighted average cost of gas forecast during the Forecast Period; plus~~

~~b. The amortization of the Core Purchased Gas Account (CPGA), which reflects the difference between actual and forecasted gas procurement costs prior to the Forecast Period; plus~~

~~c. The most recent adopted F&U factor, specified in Definitions hereunder, multiplied by the sum of the costs determined in a. and b. above.~~

2. Transportation Revenue Requirement

These revenues reflect the transportation and delivery costs of utility gas service to utility customers. It equals the sum of:

a. The utility's Gas Base Margin, which reflects the cost of gas transportation~~transmission~~ service within the utility's service territory; these costs include but are not limited to the utility's rate of return, taxes, and F&U on base cost items.~~; plus~~ T

The Gas Base Margin amount shall be the total annual base revenues authorized by the Commission. The authorized gas margin pursuant to SDG&E Advice Letter 1826-G, effective January 1, 2009, is $243,309,814. The Gas Base Margin represents the total revenue requirement less miscellaneous revenues, plus D

b. A forecast of California Alternate Rates for Energy (CARE) program costs, which reflect the costs associated with providing a 20% CARE discount to residential gas users who meet certain criteria; plus

(Continued)

PRELIMINARY STATEMENT

III. ~~BIENNIAL~~ COST ALLOCATION AND REVENUE REQUIREMENT ~~PROCEEDING (BCAP)~~

D. REVENUE REQUIREMENT (Continued)

2. Transportation Revenue Requirement (Continued)

c. The amortization of utility gas balancing accounts, which reflect an under- or over-recovery of nongas costs authorized for recovery by the Commission prior to the f~~F~~orecast p~~P~~eriod. These account balances include but are not limited to: T

(1) Core Fixed Cost Account (CFCA);~~Core Purchased Gas Account (CPGA);~~

(2) Noncore Fixed cost Account (NFCA);~~Non-margin Fixed Costs Account (NMFCA);~~

(3) Rewards and Penalties Balancing Account (RPBA);~~Gas Storage Balancing Account (GSBA);~~

(4) Self-Generation Program Memorandum Account (SGPMA);~~Interstate Transition Cost Surcharge Account (ITCS);~~

(5) Hazardous Substance Cleanup Cost Account (HSCCA);~~Natural Gas Vehicle Account (NGV);~~

(6) Integrated Transmission Balancing Account (ITBA), and ~~Real-Time Pricing Balancing Account (RTP-BA)~~ T

(7) Any other account authorized by the Commission granting full recovery of specific costs.

d. Other SDG&E-only transportation costs, which reflect additional costs associated with gas transportation service within SDG&E's service territory and are not included in 2.a. through 2.c. above. These costs include but are not limited to:

(1) storage costs, plus ~~the carrying cost of gas in storage inventory (CCSI), which reflects the opportunity costs to the utility of purchasing gas supplies in advance for use by utility customers at a later date.~~

(2) Lost and Unaccounted For (LUAF) gas and Company Use (CU) gas costs, which reflect the payment for gas that is lost due to re-pressurizing gas for delivery to utility customers at different gas pressures, pressure leaks, and similar activities; plus

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III. ~~BIENNIAL~~ COST ALLOCATION AND REVENUE REQUIREMENT~~PROCEEDING (BCAP)~~

D. REVENUE REQUIREMENT (Continued)

2. Transportation Revenue Requirement (Continued)

e. Allocated SoCalGas fixed charges, which reflect the cost of gas transportation service across the SoCalGas' service territory and itemized as follows: T

(1) SoCalGas Margin Costs: authorized Gas Base Margin items, that have been allocated from SoCalGas to SDG&E; plus T

~~(2) Transition Costs: gas costs, described in Definitions hereunder, which are identified as a result of past practices of the gas industry; plus~~

(2~~3~~) Other Transportation Charges: other SoCalGas gas transmission costs, including ~~CCSI,~~ LUAF & CU, and storage banking costs not specifically identified above and allocated to SDG&E.~~; plus~~

~~(4) Prepayment of SDG&E's Global Settlement Obligation:~~

f. Interstate Pipeline Transportation Charges, which are directly billed to the utility. T

g. ~~g.~~ The most recently adopted F&U factor~~, described in Definitions hereunder,~~ multiplied by the costs computed in 2. b. through 2. f. above (see note 1/ below). T

h. San Diego Franchise Fee and Uncollectible Factor (F&U Factor)

The San Diego Franchise Fee and Uncollectible Factor is 1.023102, based on the Last General Rate Case Decision. This factor is applicable to all retail gas service rendered within the utility's service territory

i. San Diego Franchise Fee Differential (SDFFD)

A San Diego Franchise Fee Differential of 1.03% is applied to retail customer bills in which utility gas services have been rendered within the corporate limits of the City of San Diego T

3. Cost Allocation Factors

These factors were determined pursuant to D.06-04-033 and **D.09-XX-XXX** and are used to allocate costs to the core and noncore customer classes:

	Cost Description	CORE	NONCORE
a.	Gas Base Margin	96.26%	3.74%

1/ The F&U for the Gas Base Margin is embedded in the Gas Base Margin.

(Continued)

~~E. COGENERATION DEFAULT RATES FOR TRANSPORTATION SERVICES~~

~~1. Description and Applicability~~

~~Pursuant to Decision 94-12-052, as long as the utility's UEG does not receive a discounted rate for intrastate gas transportation service, the utility is not required to calculate the UEG/Cogeneration parity rate under the formula in Resolution G-3062, dated July 21, 1993. Otherwise, pursuant to Resolution G-3062, the Commission established contemporaneous rate parity between cogenerators and utility electric generation ("UEG") customers on a service level basis beginning August 1, 1993.~~

~~Cogeneration default rates shall be refiled whenever:~~

~~a. A discounted rate for either firm or interruptible UEG transportation service is established that was not included in the utility's last adopted BCAP forecast; or~~

~~b. The nature of service under an existing discounted UEG contract changes; or~~

~~c. A discounted UEG contract expires.~~

~~Cogeneration default rates shall be revised either up or down, but they shall not rise over the tariffed rate set in the utility's last ratemaking proceeding.~~

~~Changes to cogeneration default rates should be filed by advice letter as necessary based on the conditions set forth below, but no more than once per month. These advice letter filings should be handled as compliance filings and will be effective on filing. A monthly filing is not necessary if there has been no change to the cogeneration default rate.~~

(Continued)

PRELIMINARY STATEMENT

III. BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

~~E. COGENERATION DEFAULT RATES FOR TRANSPORTATION SERVICES (Continued)~~

~~2. Rate Parity Calculations~~

~~The cogeneration and UEG average transportation rates for firm or interruptible intrastate services, respectively, shall be computed as follows:~~

~~a. Calculate UEG and cogeneration forecasted revenues for firm transportation for the cost allocation period. These revenues are the sum of:~~

~~(1) UEG firm discounted rates multiplied by its contract volumes.~~

~~(2) Standard UEG rates for firm transportation multiplied by remaining non-discounted contract volumes.~~

~~(3) Standard cogeneration rates for firm transportation multiplied by contract volumes.~~

~~b. Divide the total UEG and cogeneration forecasted revenue for firm transportation from step a. by the UEG and cogeneration forecasted firm transportation volumes. Discounted cogeneration volumes should not be included in this calculation. The result will be the firm transportation parity rate. The utility may adjust for winter and summer rates as appropriate in compliance with current Commission policy.~~

~~c. Repeat steps a. and b. substituting rates, forecasted revenues, and forecasted volumes for interruptible rather than firm transportation where appropriate. The result will be the interruptible transportation parity rate.~~

~~3. Revenue Shortfalls~~

~~A Cogeneration Shortfall Memorandum Account (CSMA) shall be established to track any revenue shortfalls resulting from establishing rate parity between cogeneration and UEG customers on a contemporaneous basis between cost allocation proceedings.~~