Application No: A.08-02-001
Exhibit No.:
Witness: Herbert S. Emmrich

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	)	A.08-02-001 (Filed February 4, 2008)

PREPARED REBUTTAL TESTIMONY

OF HERBERT S. EMMRICH

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

EMBEDDED COST STUDY, DEMAND FORECASTS AND RELATED ISSUES

PHASE II

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
January 27, 2009

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My name is Herbert S. Emmrich. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. I have previously submitted testimony in this proceeding. The purpose of my rebuttal testimony is to respond to a number of assertions by DRA's witnesses Ms. Pearlie Sabino and Ms. Jacqueline Greig and by TURN witnesses Mr. William Marcus and Mr. Michel Florio concerning:

1. The retention of the Long Run Marginal Cost New Customer Only LRMC NCO) cost allocation methodology to allocate customer-related costs to customer classes;

2. The contention by DRA and TURN that the LRMC NCO cost allocation methodology is just and reasonable;

3. The request by DRA that the underlying cost studies used by SoCalGas to develop cost allocators should be updated to reflect more current data, specifically: to update the service line footage study using 2006 data; to use historical embedded cost to allocate customer-related O&M costs; and to update the storage functional factors for inventory, injection and withdrawal based on 2007 FERC Form 2 data.

4. The DRA and TURN proposal to allocate 50% of A&G costs based on an Equal Cent Per Therm (ECPT) average year throughput basis and to allocate the remaining 50% on a MULTI factor basis only;

7. The DRA proposal to use average year throughput as the allocator for backbone transmission cost;

9. The DRA recommendation that unaccounted-for (UAF) gas costs for SDG&E be allocated on an ECPT basis instead of factors developed from the UAF gas study as shown in Appendix 1 of my prepared direct testimony;

10. TURN witness Marcus' recommendation that G-30 Peak Day marginal demand measure (MDM) should be based on a week day instead of an average day;

11. TURN's assertion that SoCalGas used the wrong peak day MDM for core storage withdrawal;

12. TURN's assertion that Gas Air Conditioning (Gas AC), Gas Engine and Natural Gas Vehicle (NGV) customers were not assigned injection and withdrawal costs;

13. TURN's assertion that SoCalGas has overstated the cost of storage assigned to ratepayers;

14. TURN's assertion that the core does not need balancing storage inventory;

15. TURN's assertion that SoCalGas misallocated return, income taxes and plant-related A&G costs and several other TURN proposals;

16. Long Beach's witness Mr. William A. Monsen's proposal that Non-DSM CS&I Major Markets' staff costs be allocated based on throughput rather than on staff time spent to provide CS&I services;

17. Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association and Watson Cogeneration Company witness Mr. Thomas Beach's proposal to use the *2008 CGR* instead of the BCAP-specific prepared gas demand forecast.

I. REBUTTAL TO DRA'S AND TURN'S EMBEDDED COST VS. LRMC TESTIMONIES

DRA witness Sabino states on page 12 of her direct testimony that the SDG&E/SoCalGas proposal to use Embedded Cost (EC) and LRMC without NCO is inconsistent with Commission decision D.00-04-060 and therefore the Commission should reject the SDG&E/SoCalGas EC and the LRMC with rental allocation proposals.

DRA consistently throughout its testimony uses past Commission decisions to argue its case but provides no evidence to repudiate the clearly cost-based and economically-superior allocation of costs among customer classes using the SDG&E/SoCalGas EC methodology. The issue is which allocation methodology is more efficient and consistent with Commission policy to allocate costs based on cost causality. The Commission has already adopted the CARE program to reduce rates for low-income households by 20%, and a Tier I baseline rate that must be at least 5% below Tier II rates for the benefit of low usage core customers. These elements of social ratemaking are reasonable and appropriate in mitigating gas costs to households with low income or elderly occupants to accommodate their special needs. It is a completely separate issue whether the Commission should modify the basic cost allocation and thereby disadvantage commercial, industrial, EOR and EG customers at a time when the business community is struggling in a momentous economic downturn that is forcing many business to close up shop, file for bankruptcy, or move out of California to avoid already high gas transportation rates. The DRA proposals, if adopted, would increase non-core, including wholesale, customers' rates by over $95 million per year or $285 million over the proposed three-year TCAP period. Therefore, SDG&E/SoCalGas believe the time is ripe to re-examine the cost allocation methodologies and revisit the fundamentals of cost causality in more equitably allocating costs to customer classes. Furthermore, the

Commission already found that EC is a just and reasonable cost allocation methodology. In the Phase One BCAP decision, D.08-12-020, dated December 4, 2008, the Commission approved the Phase One settlement which sets the cost of storage in the unbundled program based on embedded costs as follows:

"The cost of storage in the unbundled storage program for purposes of calculating net storage revenues shall be the embedded unit costs approved by the Commission in Phase Two of this proceeding and as revised in each cost allocation proceeding (BCAP or TCAP) during the term of the SA."

Therefore, the Commission has already found in Phase One of this proceeding that EC is an appropriate cost allocation method that is reasonable and in the public interest (Conclusion of Law 1).

In addition, on page 13 of DRA witness Ms. Sabino's testimony, DRA states that the Commission effectively adopted a hybrid type cost allocation for PG&E's natural gas distribution, storage and transportation business using LRMC/NCO for allocating distribution costs and EC for transmission and storage. Although allocating transmission and storage cost based on an EC allocation methodology is a step in the right direction and has proven to be effective for PG&E and its customers, a hybrid approach is not exclusively cost causality-based and therefore sub-optimal. Since the Commission has already adopted EC as the preferred cost allocation methodology for PG&E's transmission and storage costs it would be a very logical step to allocate all of SDG&E/SoCalGas' base margin costs on an EC basis. This would provide consistency of methodology and lead to a more efficient allocation of resources in the long-term.

On page 14 of DRA's testimony, Ms. Sabino correctly quotes SoCalGas' position on the Commission's implementation of LRMC as follows:

"SDG&E and SoCalGas believe that the Commission's methodological evolution in its application of LRMC for cost allocation in BCAPs over the past 15 years has resulted in measures of costs that no longer reasonably represent the true marginal costs of serving their customers."

SDG&E/SoCalGas believe that the Commission has adopted a theoretically deficient NCO method for allocating customer costs which severely understates the cost of hooking up new customers and therefore arbitrarily shifts cost to non-core customers. Both DRA and TURN continue to support this deficient methodology although it is a patently incorrect method for allocating customer costs in rates. SoCalGas' position on the deficiency of the NCO method is further described by Ms. Smith in her rebuttal testimony.

In addition, both DRA and TURN continue to support the use of utility transmission and storage resource plans going 15 years into the future. To develop and then allocate storage and transmission costs based on this artificial construct is without theoretical support and is a misapplication of LRMC.

DRA quoted my direct testimony on this issue as stated on page 6 of Ms. Sabino's direct testimony at Lines 8-10 as follows:

"In late 1992, in D.92-12-058, the Commission adopted an LRMC methodology for the three gas utilities – Pacific Gas & Electric Company (PG&E), SoCalGas, and SDG&E. All gas utilities were required to adopt the LRMC methodology for implementation by early 1993." In that decision, the Commission stated that "It is not enough for a utility to use just any combination of resources to meet the needs of customers. An appropriately planned system meets customers' needs at the lowest total cost." (FOF#2) On page 9, at Lines 2-3, of Mr. Emmrich's direct testimony we further state that "SoCalGas and SDG&E are proposing that the embedded cost method be used for allocating all base margin costs to customers."

DRA's assertion that SDG&E/SoCalGas are inconsistent with Commission decisions concerning cost allocation methodologies is not correct. First, SDG&E/SoCalGas filed a compliance case using LRMC. Therefore that issue is moot. Second, SDG&E/SoCalGas believe that the proposed change to an EC method from the mandatory LRMC methodology would ensure that the utility would meet its customers' needs at the lowest total cost as the Commission expressed in D.92-12-058. This is true because the total costs allocated using embedded costs compared to LRMC are ultimately the same. Under both cost allocation methodologies, the utility is authorized to recover the same revenue requirement. Those issues are addressed in the General Rate Case proceedings of the utilities not the BCAP. That said, if an economically efficient LRMC-based cost allocation methodology, based on cost causality, were used to allocate costs among customer classes, then the various customer classes would receive the proper price signals to use gas service efficiently. The utility could then design its system more optimally and thereby reduce total utility costs which would then translate into lower costs and rates to customers overall. However, since the Commission decided to use a hybrid LRMC, embedded cost, and social ratemaking methodology to allocate cost among customer classes, using EC would be the next best alternative cost allocation methodology to optimize the utilities total cost and therefore also reduce customers' rates over time.

A. Resource Planning Concerns

SDG&E/SoCalGas has additional concerns with the current LRMC methodology.

LRMC resource planning has rarely, if ever, resulted in actual facility additions or improvements on the SDG&E and SDG&E gas systems. In actual practice, system needs have been driven by mandated requirements for service reliability and market demand. SDG&E and SoCalGas have always striven to minimize costs as the gas systems have been improved to meet changing service obligations and market conditions, and this practice will not change with the adoption of the EC methodology.

There are also other concerns with using resource plans to calculate transmission, distribution, and storage costs. The LRMC cost allocation process requires resource plans in order to identify the incremental marginal costs of service for ratemaking purposes. This is not necessary under an EC methodology, and the resource plans themselves do not necessarily represent SoCalGas' plans to expand its transmission, distribution, or storage facilities. SoCalGas expands these facilities as necessary to meet the CPUC-mandated design conditions, its contractual obligations, and market demands.

In developing the LRMC-mandated transmission resource plan, a long term demand forecast is prepared by the Gas Forecasting Department with input from Customer Services staff, following the Commission's design standard of a 1-in-10 year cold day event for firm noncore service and a 1-in-35 year peak day event for core service. The Gas Transmission Planning Department then uses these forecasts and its hydraulic models of the SDG&E and SoCalGas gas transmission systems to evaluate the Utilities' capability to meet the forecasted levels of demand, and identify improvements and their timing if necessary to meet mandated service-reliability requirements. Gas Transmission Planning will also provide a preliminary cost estimate for any improvements identified, with guidance from the Project and Construction Management Department. These improvements then make up the resource plan for LRMC ratemaking purposes.

The distribution resource plan is a forecast of future distribution expenditures developed by the Gas Operations Business Planning Department based upon historical investments made to meet the utilities' design criteria, customer/agency requests for service, and utility service obligations on system reliability.

The storage resource plan is developed by the Energy Markets and Capacity Products Department using data from the Storage Engineering Department regarding the costs to incrementally expand the three storage products.

The design standards were most recently reaffirmed by the Commission in D.06-09-039. SDG&E/SoCalGas generally follow the above process for planning its transmission system to meet the CPUC mandated design requirements. However, SDG&E/SoCalGas may not expand its system based solely on a demand forecast. As previously explained, SDG&E/SoCalGas use the demand forecast in conjunction with customer requests for service and contractual obligations in the planning and expansion of its transmission, distribution, and storage systems.

In addition, SDG&E/SoCalGas have concerns with the resource plan and the 15-year time horizon used to develop costs and rates. It is theoretically incorrect and impractical to use forecasts of demand and costs 15 years into the future to set current rates. In a fully competitive market, prices are set at current marginal costs, not estimated marginal costs 15 years out in the future. In a competitive market, prices are set based on short run marginal costs in order to give customers the right price signal to use a product or service efficiently. When short run marginal costs are above average costs, the producer, in a free market, would charge customers the short run marginal cost of using that additional product or service; but, since the utility is regulated and only allowed to recover its average costs, utility cost recovery has to be scaled up or down to average cost to meet the revenue requirement. This scaling is currently done across all functional areas combined on an equal percent of marginal cost (EPMC) basis; i.e., transmission, storage, distribution, etc., instead of the individual functional areas; for example, transmission only, if we are looking at the marginal cost of expanding transmission. This preserves some of the price signal aspect of indicating to customers that the marginal transmission expansion is expensive and thereby is at least partially reflected in rates.

Based on basic economic theory, we know that when a perfectly competitive market is “in long run equilibrium,” short run marginal cost is equal to long run marginal cost, which is equal to average cost which is equal to price. Therefore, the economically efficient price is then based on LRMC which is equal to the long run average cost. In order to approximate this long run equilibrium price at a point in time where the utility plant has theoretically expanded to the point where long run marginal costs are equal to short run marginal costs, we do this by calculating the real economic carrying charge (RECC) over the life of the investment. The RECC includes the cost of capital, depreciation and taxes that the utility will incur to make this investment and charge customers the real dollar cost of providing that service over time. When we use a 15-year resource plan to set current rates and base those rates on the incremental demand 15 years into the future the resulting current rates are then much higher than the LRMC per unit of output.

For example, the misuse of the LRMC pricing principle is clearly pointed out by Professor Thayer Watkins of San Jose' State University in his article on marginal cost pricing:

> "Although the marginal cost pricing principle is [a] valid principle of economic welfare analysis there are some problems involved with its application. First there is the problem of how to precisely define the relevant marginal cost. This involves the question of long run versus short run marginal cost. There is also the matter of externalities referred above. There is the matter of *indivisibilities* and the question of how many production units there should be. This problem is illustrated below.
>
> Consider the cost function of an airline (total cost versus passengers carried between two points). There is a small increase in cost for each additional passenger and a big discontinuous increase when an additional plane has to be put into service. **An incorrect interpretation of the marginal cost-pricing rule would suggest that for economic efficiency the passengers should be charged the enormous cost of putting another plane into service**. **The correct interpretation of marginal cost pricing principle is that for economic efficiency the passengers should be charged the average cost per passenger of another planeload of passengers**. (Emphasis added.)
>
> As is demonstrated elsewhere, the relevant marginal cost for economic efficiency is the minimum average cost of the marginal plant (production unit) rather than the intra-plant marginal cost. When the market price is equal to this quantity it is equivalent to the condition that the marginal plant is earning no economic rent." Source: www.sjsu.edu/faculty/watkins/mcpricing.htm

Therefore, in this example, we only have to substitute an additional unit of gas for another passenger and substitute a major pipeline expansion for an additional plane to get the correct result: "The correct interpretation of marginal cost pricing principle is that for economic efficiency the ***customers*** should be charged the average cost per ***unit of throughput*** of another ***fully utilized pipeline expansion***."

Based on the above articulated concerns of using the current resource plan to develop costs and rates for SDG&E/SoCalGas, the LRMC for lumpy investments, such as major pipeline or storage expansions, should be based on the long run average cost (LRAC) which is equal to the LRMC in equilibrium. Short run marginal cost (SRMC) should be used in the decision to discontinue service when revenues no longer cover out of pocket costs or to expand service when incremental revenues cover incremental costs when holding investment constant.

B. Efficiency Benefits of Embedded Cost vs. Current LRMC Hybrid Methodology

The efficiency benefits of using a more correct LRMC methodology are evident. For example, if an economically efficient LRMC-based cost allocation methodology based on cost causality were used to allocate costs among customer classes, then the different customer classes would receive the proper price signals to use gas service efficiently. The utility could then design its system more optimally and thereby reduce total utility costs which could then translate into lower costs and rates to customers overall.

For example, medium pressure distribution costs are allocated in rates based on a marginal demand measure (MDM) of customer class throughput on a 1-in-35 year peak day. However, the medium pressure gas distribution system is based on meeting ***peak hour*** demand on a 1-in-35 year peak day. This has resulted in less cost being allocated to residential customers and core vs. non-core customers served off of the medium pressure distribution system in general. Therefore, core rates are lower and non-core rates higher due to this mismatch of cost causality and rates. Core customers would potentially use less gas if rates were based on the correct cost allocation based on cost causality. Therefore, from a theoretical perspective, the current gas distribution system could be said to be over-built because customers use more gas than is optimal if rates were based on costs incurred by the utility to provide service.

II. UPDATING OF COST STUDIES

DRA states on page 41 of Ms. Sabino's testimony that several cost studies used to develop cost allocators should be updated to reflect more current data. Specifically: that the service line footage be updated to reflect 2006 mileage; that the storage functional percentage for inventory, injection and withdrawal be based on 2007 FERC Form 2 data; and that the historical embedded cost of meters, as represented by SoCalGas' Net Book Value of meters (instead of current purchased cost of meters), be used to allocate customer-related O&M costs for distribution meters and regulators. SDG&E/SoCalGas do not agree with DRA's recommendation for the following reasons. The 2006 FERC Form 2-based cost studies completed for the February 4, 2008, BCAP filing required months of studies and analyses before being used to allocate the embedded costs in the filing. As time passed and the 2007 FERC Form 2 data became available, SDG&E/SoCalGas agreed to update the filing using the 2007 FERC Form 2 data at the three digit FERC Account level but not to update the underlying cost allocation studies. It is unreasonable to expect SDG&E/SoCalGas to update in a very short period of time what took months to comprehensively study and analyze and to then use only selected updated study-outcomes to change the filed case beyond agreed upon modifications. Using only the selected updates and outcomes recommended by DRA leads to inconclusive and unsupported cost shifts to non-core customers that reflect the cost allocation goal-seeking intention of DRA. Therefore, the Commission should reject DRA's unreasonable recommendations.

III. A&G COST ALLOCATION CONCERNS

DRA and TURN propose that SDG&E/SoCalGas allocate 50% of A&G costs based on an ECPT average year throughput basis and to allocate the remaining 50% on a MULTI factor basis only. SDG&E/SoCalGas believe that first and foremost, A&G costs are only remotely related to levels of throughput and throughput is therefore an inappropriate cost allocator. Contrary to DRA and TURN's assertions, SoCalGas analyzed and allocated A&G costs based on cost causality and the costs identified in A&G FERC Accounts that are incurred over the entire customer base were correctly allocated on a MULTI factor basis by averaging O&M, Labor and Net Plant costs. Using the MULTI factor allocation method is an acceptable and a standard allocation method for costs that cannot be closely associated with O&M, Labor or Net Plant costs exclusively. The allocation of A&G costs by FERC Account is shown below.

A&G FERC Account		Allocation Factor
920 AdmGen Op-Salaries Plus **Payroll taxes $2.9**	$2.966	A&G Func Fctrs/Labor
921 AdmGen Op-Office Supplies & Expenses		A&G Func Fctrs/Labor
922 AdmGen Op-(Less) Administrative Exp Transferred		A&G Func Fctrs/Labor
923 AdmGen Op-Outside Services Employed - General		A&G Func Fctrs/MULTI
924 AdmGen Op-Property Insurance		A&G Func Fctrs/Net Plant Factr (Ex GP)
925 AdmGen Op-Injuries & Damages		A&G Func Fctrs/MULTI
926 AdmGen Op-Employee Pensions & Benefits		A&G Func Fctrs/Labor
927 AdmGen Op-Franchise Requirements		Excluded
928 AdmGen Op-Regulatory Commission Expenses		A&G Func Fctrs/MULTI
930.2 A&G Op-MiscGen Exp(PBR Ex Public Purpose RDD)		A&G Func Fctrs/MULTI
931 AdmGen Op-Rents		A&G Func Fctrs/Labor
932 AdmGen Mnt-General Plant		A&G Func Fctrs/Labor
Total A&G Expenses		

FERC Account 920 Salaries and Payroll Taxes were allocated based on the Labor Factor. These expenses are directly tied to labor costs incurred. FERC Account 921 Office Supplies & Expenses are also directly tied to labor costs and are allocated using the Labor factor. FERC Account 922 Administrative Expenses Transferred is costs transferred from FERC Accounts 920 and 921 and are therefore correctly allocated using the Labor Factor as pointed out by TURN. FERC Account 923 Outside Services Employed are costs incurred across various sectors of the company and are therefore allocated using the MULTI Factor. FERC Account 924 Property

Insurance is directly related to Net Plant in Service and therefore is allocated using the Net Plant Factor excluding General Plant. FERC Account 925 Injuries & Damages are allocated using the MULTI factor, since these costs include labor injuries and plant-related expenses. FERC Account 926 Pension & Benefits Expenses are directly related to labor costs and are therefore allocated using the Labor factor. FERC Account 928 Regulatory Commission Expenses are allocated using the MULTI factor because these expenses are incurred across all aspects of company operations and plant. FERC Account 930.2 Expenses are allocated using the MULTI factor because these costs are incurred across all segments of the Company's operations and plant. FERC Account 931 Rents are allocated using the Labor factor because these expenses are directly related to the office space needed for housing of employees. FERC Account 932 General Plant are costs incurred to maintain office space and are directly related to labor costs and are therefore allocated using the Labor factor.

In contrast, DRA recommends that the following FERC Account costs: 920 (A&G Salaries), 921 (Office Supplies and Expenses), 926 (Employee Pension and Benefits), 931 (Rents), 408 (Payroll Taxes), 932 (Administrative and General Maintenance-General Plant) and 389.1 through 398 (General Plant Depreciation) and for General Plant Return and Taxes be allocated based on the MULTI factor instead of the Labor factor. SDG&E/SoCalGas find that even by FERC Account definition it is easy to see that all of these costs are related to labor expenses and therefore the Labor factor, those labor costs incurred to provide distribution, storage, transmission, customer accounts and non-DSM Customer Services and Information Services, is the appropriate allocation factor because these are the labor-related costs required to provide distribution, transmission and storage-related services to our customers. General Plant costs are mainly the office buildings and service facilities needed to provide the field and office personnel with the facilities needed to provide services to our customers. The number of facilities needed is based on the labor force required to provide distribution, transmission, storage and other ancillary services to our customers and therefore the Labor factor is an appropriate allocator to assign these costs to customer classes. In the LRMC decision D.92-12-058, the Commission correctly supported the allocation of General Plant based on labor costs as follows:

"The major components of general plant are buildings, furniture, computer, and communications equipment. We agree with SoCal and DRA that these components are generally purchased to support labor intensive activities and, consequently, the costs vary more with the number of employees than with miles of pipe." (D.92-12-058, page 38). It is interesting to note that DRA also supported the allocation of these costs based on labor but now has changed its mind.

Furthermore, DRA and TURN erroneously state that SoCalGas did not conduct an A&G study to allocate A&G costs. As shown in SoCalGas' EC study, A&G costs were broken down by FERC Account and then allocated based on the O&M, Labor or Net Plant factor based on the nature of the expense incurred. Those costs identified as cost incurred across all functional areas were allocated on the MULTI factor comprised of the simple average of the Labor, O&M and Net Plant factors. In addition, SoCalGas did an extensive study of FERC Account 923 (Outside Service Employed-General) the largest A&G cost category, in its February 2008 filing. That study showed that almost all Account 923 costs were cost incurred that cross all functional categories and therefore the MULTI factor was appropriately used to allocate almost all of these costs. That study was shown in WP-2 of my direct February 2008 testimony.

In updating costs with 2007 FERC Form 2 data, SoCalGas therefore appropriately allocated all Account 923 costs based on the MULTI factor. For DRA now to say that SoCalGas did not do a new A&G study is inappropriate and not consistent with the study included in my testimony. Therefore, the Commission should reject DRA's and TURN's proposal and allow SDG&E/SoCalGas to allocate A&G costs based on the studies conducted. Neither DRA nor TURN has submitted any evidence to show that these allocation methods are inconsistent with cost causality principles.

DRA and TURN also recommend that 50% of A&G costs should be allocated based on average year throughput because SDG&E/SoCalGas did not do an A&G study. Throughput is only remotely related to base margin A&G costs incurred. For example, if throughput were to be reduced by 10%, base margin A&G costs would not be reduced by 10% or any significant fraction thereof. Similarly, if throughput were to increase by 10% base margin A&G costs would not increase by 10% or any significant fraction thereof. Those costs that are directly affected by throughput, transmission fuel and storage fuel and marginal storage O&M expenses are excluded from base margin. However, when new customers are added, the utilities' capital, labor and O&M expenses costs directly increase. Therefore, arbitrarily allocating A&G costs based on throughput is inappropriate, not cost causality based, and clearly designed by DRA and TURN to arbitrarily allocate more costs to non-core customers.

The current DRA/TURN 50% throughput-based A&G cost allocation proposal has been proposed in previous proceedings. The allocation of A&G costs was a key issue in the long-term rate design proceedings in 1986 and subsequent proceedings. In those proceedings both the Commission staff (then known as PSD) and the utilities proposed the "functionalization" of A&G

expenses into storage, transmission, common distribution, and customer-related functional cost classification on a pro rated basis. TURN proposed allocating A&G costs on an ECPT basis. The Commission ruled as follows:

"In view of our policy of moderating the impact of extreme allocations, we will adopt a compromise between the PSD and TURN methods: 50% of A&G expenses will be classified as commodity-related and allocated on and equal cents per therm basis and 50% will be classified in the same manner as O&M expenses. This compromise reasonably balances the uncertainties in the classification of A&G expenses. In the future, we expect to be revisiting our cost allocation on a regular basis, perhaps as often as once per year. We are willing to revisit the issue of classification of A&G expenses during one of those revisions, if better information becomes available on how these costs should be classified." (D.86-12-009, pp. 25-26.)

The Commission modified its position in D.87-05-046. In that decision, the Commission essentially exempted wholesale customers from the ECPT allocation of the 50% of A&G expense portion. For wholesale customers the Commission decided to retain the status quo which is based on 100% functionalization of A&G expenses. The Commission ruled as follows:

"The Commission is concerned about the impact that our adopted allocation method has had on SoCal's wholesale customers. Until we have developed a better record on the A&G allocation issue, the more equitable approach would be to maintain the status quo with respect to the assignment of A&G expense to SoCal's wholesale customers. Therefore, we will grant SDG&E's request." (D87-05-046, p. 25)

DRA's and TURN's current proposal is therefore inconsistent with Commission decision D.87-05-046 and contrary to the cost causality principle of allocating costs to customer classes and should therefore again be rejected and the Commission should allow SDG&E/SoCalGas to allocate A&G costs on a fully functional basis.

Furthermore, the Commission approved SoCalGas' allocation of marginal A&G costs in the LRMC decision. The Commission found as follows:

"SoCal followed an appropriate approach for calculating marginal A&G expenses. SoCal analyzes the extent to which each marginal is nonmarginal and its A&G study shows that approximately 51% of its A&G costs are marginal. PG&E and SDG&E should perform their own system studies applying SoCal's analysis." (D.92-12-058, page 67).

Likewise, SDG&E/SoCalGas used an appropriate study and analysis in allocating A&G costs based on embedded costs incurred to provide services to customer classes.

IV. UNACCOUNTED-FOR GAS STUDIES

DRA witness Ms. Jacqueline Greig recommends that unaccounted-for (UAF) gas costs for SDG&E be allocated on an ECPT basis instead of on the factors developed by the UAF gas study as shown in my direct testimony in Appendix 1. DRA witness Ms. Greig bases her recommendation on the incorrect notion that SDG&E/SoCalGas completed a study of SoCalGas' UAF gas for SoCalGas but did not complete such a study for SDG&E. That is incorrect. SoCalGas did a comprehensive UAF gas study in 1991 that laid out all of the parameters and elements of UAF gas and calculated the UAF gas attributable to core versus non-core customers. For the 2009 BCAP, SoCalGas' Engineering Department replicated that study and updated it based on 2006 actual throughput and temperature conditions. That study has been accepted by DRA stating on page 5 of Ms. Greig's direct testimony, "… DRA does not oppose the proposed UAF gas core/noncore allocations for SoCalGas; it opposes the proposed UAF gas allocation for SDG&E's core and noncore customers." However, the UAF gas study prepared by the Engineering Department for SoCalGas is exactly the same for SDG&E. This is shown in Appendix 1, Table 2, of my direct testimony and as shown below.

Table 2
SDG&E UAF Study

Line Item	Department	1991 Subcomponents	SDG&E 2006 % of LUAF	2006 LAUF Volumes (MCF)	2006 LUAF MMBtus	SD % Non-core	SD 2006 Non-core LUAF MMBtus	SD 2006 Core LUAF MMBtus	SD % core
A	Accounting	Cycle Billing Adjustments	0.00%	0	0	0.00%	-	-	
B	Accounting	Company-Use Gas	0.20%	3,021	3,074	59.45%	1,827	1,246	40.55%
C	Accounting	Bypass	0.00%	0	0	0.00%	-	-	
D	Accounting	Slow Meters	0.00%	38	38	0.00%	-	38	100.00%
E	Accounting	DR Meters	0.03%	403	410	0.00%	-	410	100.00%
F	Accounting	No-Close Policy	3.92%	59,368	60,400	0.00%	-	60,400	100.00%
G	Accounting	Other Estimated	0.00%	0	0	0.00%	-	-	
H	Accounting	Other Actual	0.00%	0	0	0.00%	-	-	
I	Measurement Regulation & Control	Fixed-Factor Temperature	-11.62%	-176,217	-179,281	0.00%	-	(179,281)	100.00%
J	Measurement Regulation & Control	Fixed-Factor Pressure	3.30%	50,035	50,905	0.00%	-	50,905	100.00%
K	Measurement Regulation & Control	Elevation and Barometric Pressure	12.83%	194,497	197,879	0.00%	-	197,879	100.00%
L	Measurement Regulation & Control	Fixed-Factor For Calculation of Z	-1.07%	-16,164	-16,445	0.00%	-	(16,445)	100.00%
M	Measurement Regulation & Control	Positive Displacement Meter Accuracy	35.90%	544,219	553,681	0.07%	376	553,305	99.93%
N	Measurement Regulation & Control	Orifice Meter Accuracy	-1.72%	-26,052	-26,505	57.55%	(15,255)	(11,250)	42.45%
O	Measurement Regulation & Control	Ultrasonic Meter Accuracy	33.58%	509,059	517,910	44.83%	232,171	285,739	55.17%
P	Measurement Regulation & Control	Turbine Meter Accuracy	-4.83%	-73,178	-74,450	96.69%	(71,985)	(2,465)	3.31%
Q	Measurement Regulation & Control	Instrument Calibration Bias	-0.75%	-11,325	-11,522	89.04%	(10,260)	(1,262)	10.96%
R	Measurement Regulation & Control	Ambient Temperature Effect on Instrumentation	0.00%	0	0	0.00%	-	-	
S	Measurement Regulation & Control	Chart Integration Bias	0.00%	0	0	0.00%	-	-	
T	Distribution Pipeline	Distribution Leakage	6.55%	99,378	101,106	23.52%	23,780	77,326	76.48%
U	Transmission Pipeline	Transmission Leakage	0.19%	2,948	2,999	59.45%	1,783	1,216	40.55%
V	Accounting	Theft	3.57%	54,134	55,075	25.72%	14,168	40,908	74.28%
W	NA	Non-Study Components	19.92%	301,947	307,197	59.45%	182,629	124,569	40.55%
	Total		**100.00%**	**1,516,111**	**1,542,472**	**23.29%**	**359,235**	**1,183,237**	**76.71%**

2006 Total Gas Delivered MCF:	**119,689,634**
2006 LUAF % of Total Gas Delivered:	**1.2667%**
2006 Total LUAF MCF:	**1,516,111**
2006 Total MMBtus Delivered:	**121,770,685**
2006 Total MMBtu LUAF:	**1,542,472**
2006 System Average BTU Factor:	**1.017**

LUAF Factor Total	LUAF Factor NC	LUAF Factor Core
1.27%	0.30%	0.97%
Allocation	**Allocation NC**	**Allocation Core**
100%	23.29%	76.71%

Since DRA finds the UAF gas allocation between core and noncore customers acceptable for SoCalGas, then the allocation of SDG&E's UAF gas between core and noncore customers should also be acceptable because they are based on exactly the same UAF gas study methodology. Therefore, SDG&E/SoCalGas recommend that the Commission adopt the proposed UAF gas allocation percentages between core and noncore customers based on the comprehensive analyses prepared by the Engineering Department for both SDG&E and SoCalGas.

V. TURN's MDM AND STORAGE-RELATED COST ALLOCATION PROPOSALS

TURN's witness Mr. Marcus (Marcus page 3) recommends that the MDM for Schedule G-30 Peak Day should be based on a week day instead of average day. SoCalGas calculated the increased usage of Schedule G-30 non-core Commercial and Industrial customers based on heating degree days consistent with the calculation of peak day for core customers. A peak day can occur on any day of the week, as shown in the table below, and just like non-core C&I customers, core C&I customers have higher usage on weekdays.

SoCalGas Core Peak Day (MMcfd)

Year	Core	Date	Day of week
1994	2,126	12/8/1994	Thursday
1995	2,124	1/4/1995	Wednesday
1996	2,407	2/27/1996	Tuesday
1997	2,140	1/15/1997	Wednesday
1998	2,634	12/21/1998	Monday
1999	2,279	2/10/1999	Wednesday
2000	2,344	3/5/2000	Sunday
2001	2,428	2/13/2001	Tuesday
2002	2,617	1/29/2002	Tuesday
2003	2,239	12/28/2003	Sunday
2004	2,469	11/29/2004	Monday
2005	2,754	12/15/2005	Thursday
2006	2,460	12/18/2006	Monday
2007	2,953	1/15/2007	Monday
2008	2,559	12/17/2008	Wednesday

Source: SoCalGas PDOS

Therefore, based on temperature data, SoCalGas calculates peak day usage on a theoretical peak day in December where the average temperature in the SoCalGas service area is 38 degrees Fahrenheit or 17 Heating Degree Days (HDD) (Note: 1 HDD is when the average temperature is 1 degree below 65 degrees Fahrenheit). In the past, peak temperature days have occurred on weekdays and weekends and therefore using the average usage increase of those peak days is a reasonable calculation methodology to use to forecast peak day demand by each customer class. TURN (Marcus page 4) further asserts that SoCalGas used the wrong peak day MDM for core storage withdrawal. The MDM approved by the Commission in the LRMC decision used Peak Day as the MDM for medium pressure distribution customers. Core storage withdrawal is used to serve core customers on a peak day and therefore the proper Peak Day is related to medium-pressure core customer demand. Secondly, Gas AC, Gas Engine and NGV customers are not winter peaking and therefore assigning any withdrawal costs to these customers is not appropriate since they can all be served with flowing supply and do not require storage because they are not temperature sensitive. TURN (Marcus page 4) also asserts that Gas AC, Gas Engine and NGV customers should be assigned injection and withdrawal costs. However, these customers are not temperature sensitive and therefore they do not cause SoCalGas to use storage to serve them. These customer classes are generally flat load or summer peaking and have a counter cyclical load profile.

TURN (Marcus page 5) also asserts that SoCalGas has overstated the cost of storage assigned to ratepayers by misallocating some Non-DSM CS&I costs to customers. In the FERC Form 2 accounting system, unbundled storage marketing costs are classified as Storage O&M in account 814 in the amount of $353,300. Those costs were removed from FERC account 814 because those are TBS marketing costs not directly related to storage operations. These costs were therefore removed from storage O&M and directly assigned to the Transaction Based Storage (TBS) program in the Non-DSM CS&I tab cell W-35 of Emmrich EC-Workpaper 1 and cell E-9 in the Base Margin & Function tab. In the SoCalGas FERC accounting system, these costs are not accounted for in the Major Markets organizational area where the TBS staff resides and therefore had to be directly assigned to the TBS program. All of the other Non-DSM C&I costs shown in the Non-DSM CS&I tab do not include TBS storage-related costs and therefore all of those costs were assigned to customer classes based on staff required to provide those services to each customer class. If this had not been done then all storage customers, core and non-core would have been assigned these TBS marketing costs incorrectly. The core is therefore correctly not assigned any of these TBS marketing cost and SoCalGas believes that TURN may not be using the updated Errata filing and therefore misinterprets the cost allocation.

TURN (Marcus page 5) asserts that the core does not need balancing storage inventory. Since the core storage issues were resolved through a Settlement which the Commission approved in D. 08-12-020 the issue is moot. The Phase One Settlement adopted the following storage capacity and revenue sharing issues:

1. SoCalGas will maintain the following storage capacities during the BCAP/TCAP Period:

SoCalGas Storage Inventory	131.1 BCF
SoCalGas storage Injection	850 MMcfd
SoCalGas storage Withdrawal	3,195 MMcfd

2. SoCalGas/SDG&E Storage Capacities:

SoCalGas/SDG&E Core Storage Inventory	79 BCF
SoCalGas/SDG&E Core Storage Injection	369 MMcfd
SoCalGas/SDG&E Core Storage Withdrawal	2,225 MMcfd

3. Customer Balancing at 10% Monthly and 10% Daily during Winter Operating Period.

4. Balancing Storage Capacities

Non-Core Balancing Inventory	4.2 BCF (**ex. Core)**
Balancing Injection	200 MMcfd
Balancing Withdrawal	340 MMcfd

5. Unbundled Storage Program including Long Beach and Southwest Gas

Inventory	47.9 BCF
Injection	281 MMcfd
Withdrawal	630 MMcfd

6. Long Beach and Southwest Gas storage capacity costs at core rates.

7. Core Inventory increase of 4 BCF and Non-core at 3 BCF from April 1, 2010 to April 1, 2014.

8. Increase in Aliso Canyon storage injection capacity of 145 MMcfd as commercially feasible.

9. Revenue Sharing

a. Embedded Cost of Storage as determined by the Commission in Phase II of the BCAP used to establish base costs of storage.

b. First $15 million of net revenues above embedded cost of storage 90/10 Ratepayer/Shareholder

c. Next $15 million 75/25 Ratepayer/Shareholder

d. Above $30 million 50/50 Ratepayer/Shareholder

e. Cap of $20 million annual shareholder earnings.

The cost allocation will be updated to reflect the now approved core storage capacities which exclude balancing inventory for the core as shown in the tables below. However, Mr. Marcus incorrectly reassigns the 1.2 core balancing inventory to the unbundled TBS storage market when instead the inventory is assigned to the non-core balancing inventory. The following two tables show the cost allocation with SDG&E/SoCalGas' proposed cost allocation and Phase One Settlement incorporated.

Storage Functional Factor									
Core Reservation SoCalGas		Percent of Total by Product		Alloc	Total	Units	Costs $MM		
	Inventory	%	53.39%	70.0	131.1	Bcf	$16.353	0.227	$/Dth
	Injection	%	38.48%	327	850	MMcfd	$9.657	28.658	$/Dth
	Withdrawal	%	60.56%	1,935	3,195	MMcfd	$18.813	9.438	$/Dth
	Total SCG Core						**$44.823**		
Core Reservation SDG&E									
	Inventory	%	6.86%	9.0	131.1	Bcf	$2.102	0.227	$/Dth
	Injection	%	4.95%	42	850	MMcfd	$1.242	28.658	$/Dth
	Withdrawal	%	9.08%	290	3,195	MMcfd	$2.820	9.438	$/Dth
	Total SDG&E Core						**$6.164**		
Total Core Reservation SCG & SDG&E									
	Inventory	%	60.26%	79.0	131.1	Bcf	$18.455	0.227	$/Dth
	Injection	%	43.43%	369.2	850	MMcfd	$10.899	28.658	$/Dth
	Withdrawal	%	69.64%	2,225.0	3,195	MMcfd	$21.633	9.438	$/Dth
	Total SCG & SDG&E						**$50.987**		
Load Balancing				Alloc	Total	Units			
	Inventory	%	3.20%	4.2	131.1	Bcf	$0.981	0.227	$/Dth
	Injection	%	23.53%	200	850	MMcfd	$5.905	28.658	$/Dth
	Withdrawal	%	10.64%	340	3,195	MMcfd	$3.306	9.438	$/Dth
	Total Balancing						**$10.192**		
	Total Core + Balancing						**$61.179**		
TBS and other Storage Programs				Alloc	Total	Units			
	Inventory	%	36.54%	47.9	131.1	Bcf	$11.190	0.227	$/Dth
	Injection	%	33.04%	280.8	850	MMcfd	$8.291	28.658	$/Dth
	Withdrawal	%	19.72%	630.0	3,195	MMcfd	$6.125	9.438	$/Dth
	Total TBS including Long Beach and Southwest Gas						**$25.607**		
	Storage Grand Total						**$86.785**		

Allocation of Base Margin by Customer Class

Customer Class	Embedded Cost Allocation ($ Millions)	Average year Throughput (MDth)	Cents/Therm	Percent of Total Cost
Residential	$1,205.1	2,484	$0.485	76.7%
Core C&I	$193.7	971	$0.200	12.3%
Gas AC	$0.0	1	$0.032	0.0%
Gas Engine	$1.9	18	$0.106	0.1%
NGV	$4.2	117	$0.036	0.3%
Total Core	**$1,405.0**	3,591	$0.391	89.4%
Non-Core C&I	$45.5	1,440	$0.032	2.9%
Electric Generation	$53.7	2,827	$0.019	3.4%
EOR	$3.9	156	$0.025	0.3%
Total Retail Non-Core	**$103.1**	4,423	$0.023	6.6%
Wholesale & International				
Long Beach	$2.7	117	$0.023	0.2%
SDG&E	$29.3	1,227	$0.024	1.9%
Southwest Gas	$1.8	82	$0.023	0.1%
Vernon	$2.1	116	$0.018	0.1%
DGN	$1.1	54	$0.020	0.1%
Total Wholesale & Inter.	**$37.1**	1,596	$0.023	2.4%
TBS Storage	**$25.6**	N/A		1.6%
Total Base Margin	**$1,570.827**	9,611	$0.163	100.0%

VI. TURN'S CAPITAL AND O&M-RELATED COST ALLOCATION PROPOSALS

TURN (Marcus page 6) asserts that SoCalGas misallocated Return, Income Taxes and Plant-related A&G. SoCalGas used the Net Book Value as per 2007 FERC Form 2 as an allocator of Rate Base. The data provided by the SoCalGas Plant Accounting Department are shown in my direct testimony in Tables 4 and 6. Using this allocation method Distribution-related rate base was calculated to be $2,001 million or 75.8% of SoCalGas $2,642 million of total rate base. Given that SoCalGas has 99% of its 5.3 million customers served off of the distribution system it is surprising that only 75.8% of its rate bases is distribution related. Therefore the rate base cost allocation to storage, transmission, distribution and general plant-related net plant in service by functional areas is reasonable and TURN's objections should be rejected by the Commission.

TURN (Marcus page 7) further incorrectly asserts that Income Taxes and Property Taxes were assigned as O&M costs by SoCalGas. As is clearly shown in my EC Workpaper 1 in the Return tab, all Income and Property Taxes were assigned to functional areas based on rate base in each functional area: transmission, storage, distribution and general plant as shown below.

	Weighted Avg. Rate Base 2006	**% Total**	**Functionalize Total Return**	Functionalize Income Taxes	Functionalize Ad Valorem Tax FERC Form 2 p. 263a	**Functionalize Capital-Related Taxes**
Storage Including Cushion Gas	$145.446	5.5%	**$12.620**	$6.301	$1.896	**$8.197**
Transmission	$352.035	13.3%	**$30.545**	$15.250	$4.589	**$19.840**
Distribution (ex NGV)	$1,995.891	75.6%	**$173.177**	$86.463	$26.019	**$112.482**
NGV	$5.414	0.2%	**$0.470**	$0.235	$0.071	**$0.305**
General Plant & Intangibles	$142.857	5.4%	**$12.395**	$6.189	$1.862	**$8.051**
Total NBV	**$2,641.643**	100.0%	$229.207	**$114.437**	$34.438	**$148.875**
Net Plant Excluding GP	**$2,498.786**	94.6%	**$216.812**	$108.248	$32.575	**$140.824**

TURN (Marcus page 7) also asserts that SoCalGas use of the net plant factor is not correct. As already explained above, using the net plant as reported in the 2007 FERC Form 2 is a reasonable allocation methodology. TURN simply does not like the result of using this allocation methodology and calls it incorrect when it is in fact reasonable.

TURN (Marcus page 7) states that in allocating Account 922 costs SoCalGas should have used the same allocation factors as was used for Accounts 920 and 921 since some of these costs are cost transfers from Accounts 920 and 921. Since it is true that all FERC Account 920 and 921 costs are allocated using the labor factor, all Account 922 costs transferred from these accounts should also be allocated using the Labor factor. SoCalGas will make that change in the final cost allocation calculation.

TURN (Marcus page 8) asserts that SoCalGas has overstated customer-related costs of distribution O&M and understates the costs of complex high-pressure systems. SoCalGas used high and medium pressure distribution footage to assign cost in Accounts 875 and 879 to customer classes. This is a reasonable allocation of these costs because metering and regulating stations are closely related to distribution main footage. TURN’s 50/50 cost assignment scheme is not based on any facts but is simply an attempt to push costs to non-core customers and should be seen as such by the Commission.

TURN (Marcus page 9) also recommends that Account 874 Maintenance of Mains and Services’ Leak Surveys be 100% allocated based on demand with a double allocation to high pressure mains. Leak surveys’ costs are related to the feet of distribution pipe in the ground. All Account 874 costs are allocated by high pressure and medium footage and footage is therefore the most reasonable allocation methodology.

TURN (Marcus page 9) states that Hazardous Waste costs in subaccounts 880502, 880506 and 880900 should be allocated 100% as demand related. As explained to TURN in a data request response, hazardous waste costs are not included in base margin. It is clearly shown that hazardous waste costs are excluded from base margin in my EC WP-1 in the Base Margin and Functions tab. Hazardous waste costs are allocated below the line on an ECPT basis and the tracking of these costs is consistent with D.94-05-020. The reference to the work paper by TURN is correct but since the hazardous waste costs are excluded from Account 880 there is no allocation of these costs based on the percentages shown in the work paper.

TURN (Marcus page 10) states that Account 887, Maintenance of Mains, should be allocated based on low-pressure and twice as high for high-pressure mains. The allocation of Distribution O&M costs by FERC Account was based on a special study prepared by Distribution Staff as shown in Workpaper Table A-1 as shown in my EC Workpaper-1 in the Distribution O&M Func Factors tab starting at Cell V-8. TURN does not provide any evidence to support its position compared to the extensive study prepared by Distribution Staff. Therefore, the Commission should reject TURN’s subjective proposal.

TURN states (Marcus page 8) that FERC Account 893, Maintenance of Medium and Large Meters, cost allocation overcharges small customers and that 1.89% of CS&I costs are arbitrarily assigned to the residential class. However, SoCalGas already accounted for the slightly higher cost of maintaining larger meters by multiplying the number of meters by size in each customer class by the replacement cost of meters by size. This is shown in my EC WP-1 in the Allocators tab starting in Cell E-6 and meter unit costs are shown in Emmrich EC WP-30. In addition, SoCalGas has separated out the higher cost of Gauges, Meters with more than 8 inches of water column, and gas energy measurement system (GEMS) costs and assigned them to customer classes based on the number of meters by size as described in my direct errata testimony on page 49.

TURN (Marcus page 13) states that small C&I customers were allocated too much Non-DSM CS&I costs. The Non-DSM CS&I cost assigned to Large C&I customers, those customers with more than 50,000 therms of usage or more per year is correctly based on the number of customers. The total number of Large C&I customers is 215,991. The total Large G-10 C&I customers is 215,286 (99.7%) and the number in the G-30 class is 705 (0.3%). Taking the $6 million of Non-DSM CS&I costs assigned to the G-10 class and dividing it by the number of G-10 customers, results in an average cost of only $29/per year to provide these services. In comparison, $430,000 of Non-DSM CS&I Energy Markets Staff's costs is assigned to G-30 customers or $610/customer per year, while only $123,000 or 57 cents per customer per year of Energy Markets staff's cost is assigned to G-10 customers. These data are shown in my EC WP-1 in the Non-DSM CS&I Allocators tab. The Commission should therefore reject TURN's proposal.

The reallocation of 1.89% of Non-DSM CS&I costs was already explained above. Although the TBS staff resides organizationally in the Non-DSM CS&I Major Markets staff, their costs are assigned to Storage O&M FERC Account 814. These costs were removed from Account 814 and directly assigned to the TBS program costs. Since this fully accounts for the TBS staff's costs that are organizationally in the Non-DSM CS&I area, all remaining Non-DSM CS&I costs are allocated by customer count as shown in my EC WP-1 in the NonDSM CSI Allocators tab. It also appears that TURN may not be using the updated errata filing of WP-1 where some of these allocations were corrected.

TURN states (Marcus page 21) that there are inconsistencies in the residential customer breakdown. The quoted figure of 42,000 master meter customers is correct. Mr. Marcus appears to be equating the number of master meters with the number of actual customers that are sub-metered behind the master meter. Mr. Lenart will correct sub-metered accounts in his rate design model to be consistent with my forecast.

TURN recommends (Marcus page 23) that metering and regulation station costs should be allocated 50% to high pressure and 50% to medium pressure. SoCalGas finds that metering and regulating stations are more appropriately assigned to medium and high pressure customers based on footage because these meters and stations are closely related to the miles of high pressure and medium pressure pipe in service.

VII. LONG BEACH'S NON-DSM CS&I STAFF COST ALLOCATION PROPOSAL

Long Beach's witness Mr. William A. Monsen's proposes that Non-DSM CS&I Major markets staffs' cost be allocated based on throughput rather than on staff time spent to provide CS&I services. The low $255,000 of Non-DSM CS&I cost assigned to Long Beach is clearly a reasonable number especially since Long Beach is a major intervener and in all of SoCalGas' regulatory issues related to cost allocation and throughput and other ongoing contract-related issues. The cost of providing these services is related to the number of customers not throughput. In addition, the Major Markets group is a shared services organization and those costs incurred to provide services to SDG&E are directly assigned to SDG&E and therefore are already accounted for in SDG&E's cost allocation.

VIII. DEMAND FORECASTS

Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association and Watson Cogeneration Company witness Mr. Thomas Beach proposes, on page 25 of his testimony, that the SoCalGas/SDG&E BCAP throughput forecast be changed to the *2008 California Gas Report* (CGR) forecast. However, as can be seen by the comparison table below, the BCAP forecast is only 0.2% different than the 2008 CGR forecast with the non-core forecast being only -0.1% different. SDG&E/SoCalGas believe that the BCAP forecast should continue to be used since it is rate specific and therefore more useful for cost allocation purposes. The CGR forecast is geared more toward capacity adequacy-related issues and therefore the entire CGR 2008 forecast would have to be modified to provide the necessary throughput data for cost allocation purposes. In addition, DRA witness Mr. Renaghan supports the SDG&E/SoCalGas BCAP demand forecast presented by me in this proceeding.

Comparison of 2008 CGR Average Year Throughput to 2009 BCAP filed AYT			
	CGR Avg. 2009-2011	BCAP Avg. 2009-2011	% change
Total Core	361,339	359,103	0.6%
Total Retail Non-core	444,304	442,331	0.4%
Total Wholesale & Intl.	157,585	159,924	-1.5%
Total Noncore	601,889	602,255	-0.1%
Total Average Year	963,228	961,358	0.2%

SCGC's witness Ms. Cathy Yap states on pages 23 through 26 of her direct testimony that SoCalGas/SDG&E have made an error in forecasting Peak Day demand for the EG class of customers. Per SCGC, "SoCalGas/SDG&E *have not forecasted the EG contribution to the system peak*", Yap, page 24. This is incorrect. Ms. Yap has confused historical operating data with demand forecast process.

In the response to IWC-01, Q 5 (Attachment A), SoCalGas/SDG&E explained that the historical high demand days on the SDG&E/SoCalGas gas transmission system may not have coincided with historical high EG demand for any given year. However, for resource planning purposes, SDG&E/SoCalGas must assume that the forecast high EG demand <u>may</u> happen coincident with the core and other noncore customer high demands.

Under the 1-in-10 year cold day design condition for firm noncore service, SDG&E/SoCalGas calculate the core load under that temperature condition and in addition analyze the potential non-core load that could add to that core 1-in-10 year cold day temperature-related demand. Non-core Commercial and Industrial (C&I) load is relatively flat and not temperature sensitive and therefore the estimate for that load is based on the non-core C&I load in the cold month, December, daily average demand. The forecast in the cold month, December, for the EG load is more problematic and requires a more sophisticated approach because EG load is more volatile by its very nature. Therefore, SDG&E/SoCalGas run their EG Load Dispatch model, as described by Mr. Anderson, to forecast the peak EG requirement in December of each TCAP year to assure that SoCalGas/SDG&E have adequate capacity available to meet all forecasted demand under the 1-in-10 year cold day design condition. The methodology has been used consistently in the planning process as described by Mr. Bisi and SDG&E/SoCalGas make investment decisions based on this Commission-mandated design requirement (in addition to the 1-in-35 year peak day design condition for core service). Therefore, SDG&E/SoCalGas have properly forecasted the EG contribution to our long-term demand forecasts. To use average EG demand, as SCGC suggests, would severely underestimate the 1-in-10 year cold day design condition and leave SDG&E/SoCalGas short of the needed pipeline capacity.

This concludes my rebuttal testimony.

ATTACHMENT A

<u>QUESTION 5:</u>

Please provide the following data on SoCalGas' and SDG&E's actual annual peak day demand in each of the last ten years (1998 to 2007):

a. The date of the peak day demand.

b. The average daily temperature in SoCalGas' and SDG&E's service territories.

c. The peak day demand for each of SoCalGas' and SDG&E's customer classes.

d. The loads that SoCalGas and/or SDG&E curtailed or that switched to alternate fuels on the annual peak day.

<u>RESPONSE 5:</u>

The peak day demand for each customer class, the date of the peak day demand, and average daily temperature (Q5-a, b, c) are shown in the attached spreadsheet.

IWC-01-Q5.xls

Q5-d.

There was no curtailment of the SoCalGas system during the 10 year period specified. On the SDG&E system, a total of 96 MMcf were curtailed on the 11/15/2000 peak day.