Application No: A. 11-11-002
Exhibit No.:
Witness: Joseph Mock

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, 2013, in Their Triennial Cost Allocation Proceeding	A.11-11-002_ (Filed November 1, 2011)

REVISED UPDATED PREPARED DIRECT TESTIMONY

OF JOSEPH MOCK

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

February 22, 2013

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REVISED UPDATED PREPARED DIRECT TESTIMONY

OF JOSEPH MOCK

I. QUALIFICATIONS

My name is Joseph Mock. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by the Southern California Gas Company (SoCalGas) as a Principal Regulatory Economic Advisor in the Regulatory Affairs Department for SoCalGas and San Diego Gas & Electric Company (SDG&E).

I hold a Bachelor of Science degree in Mechanical Engineering and a Master of Business Administration degree with an emphasis in Financial Decision Systems, both from Loyola Marymount University in Los Angeles, California. I have been employed by SoCalGas since 2006; first as an Account Executive in Commercial & Industrial Services, and also as an Engineer in Gas Transmission Planning. I have been in my current position since November, 2010.

II. PURPOSE

The purpose of my testimony is to update the Long-Run Marginal Cost (LRMC) study for SDG&E's customer cost and gas distribution service functions and to allocate gas base margin to SDG&E's six customer classes. My testimony is organized as follows:

- Section III provides an overview of the cost allocation methodology;
- Section IV derives customer-related marginal costs;
- Section V explains the derivation of demand-related distribution marginal costs;
- Section VI presents SDG&E's Real Economic Carrying Charges and marginal loading factors;

- Section VII summarizes the method for allocating gas base margin to SDG&E's customer classes; and
- Section VIII shows the allocated costs.

III. COST ALLOCATION PROPOSAL FOR SDG&E

SDG&E proposes to continue the cost allocation framework adopted by the California Public Utilities Commission (Commission) in Decision (D).09-11-006. Namely, SDG&E uses an LRMC study to allocate costs to its customer cost, medium-pressure distribution, and high-pressure distribution functions and an Embedded Cost Study (ECS) to allocate costs to its transmission function. A separate study for the Natural Gas Vehicle (NGV) compression adder is presented in the testimony of Mr. Bonnett. SDG&E followed the same cost allocation principles discussed in Section II of the testimony of Mr. Lenart.

Customer costs reflect the capital and expenses incurred by SDG&E to provide customer access to the gas supply system. Medium-pressure and high-pressure distribution costs are associated with building and maintaining systems that deliver gas to customer load centers from the gas transmission system. Transmission costs are those required to deliver gas from non-local receipt points to distribution centers inside SDG&E's service territory. The ECS for SDG&E transmission costs is discussed in the testimony of Ms. Fung.

Marginal costs are based on the incremental costs incurred by SDG&E to provide an additional unit of output and for the purposes of this LRMC study include both capital and O&M expense-related costs. Marginal customer costs are derived using engineering-based calculations of customer connection equipment, including meters, regulators, and service lines, as well as corresponding marginal expenses. The "rental" methodology is used to determine marginal

customer costs per customer, and results in one effective marginal unit cost for all customers in each rate class.

Distribution marginal costs are calculated by taking a linear regression of 15 years of demand and investment data (ten years of which are historical and five years forecasted). Cumulative marginal investment serves as the dependent variable while cumulative marginal peak-day demand is the independent variable. This analysis is completed separately for both the medium-pressure and high-pressure distribution systems. The unit marginal capital costs are equal to the resulting regression coefficients.

SDG&E's authorized margin is allocated to customer classes using marginal demand measures applied to the marginal unit costs. These demand measures were established in the LRMC Decision (D.) 92-15-058 and updated in the 2009 Biennial Cost Allocation Proceeding (BCAP) D.09-11-006. This includes allocating distribution costs using peak-day demand and customer costs using the total number of customers per class. SDG&E allocates costs to three core customer classes and three noncore customer classes. The three core classes are residential, core commercial and industrial, and natural gas vehicle stations. The noncore customer classes are commercial and industrial, small electric generation (< 3 million therms per year) and large electric generation (> 3 million therms per year).

IV. CUSTOMER-RELATED MARGINAL COSTS

Customer-related marginal costs include both marginal capital costs as well as marginal O&M expense-related costs. SDG&E calculates marginal capital customer costs using the rental method, as discussed in Section III of the testimony of Mr. Lenart, to determine the annualized cost of Service lines, Regulators, and Meters (SRM) for each customer class. O&M loader costs are derived in Section VI.

A. Marginal Capital Costs

SRM costs reflect the installed capital expense associated with providing customer access to the gas supply system. These costs include gas meters, regulators, pipes, and installation labor. The SDG&E Gas Distribution Engineering Department provides updated customer data, including:

- Meter size, type, regulator, fitting costs and installation costs;
- Updated service footages;
- Updated service costs for new hook ups and replacements;
- Updated costs of service line installations; and
- Updated series of flow ranges, and corresponding equipment profiles, at each range.

Twenty-six flow ranges are identified for which SRM costs are summarized. These total capital costs are annualized using corresponding Real Economic Carrying Charge (RECC) factors, which are presented for SDG&E in Section VI. The annualized costs are multiplied by the number of meters each customer class has represented within each flow range to determine the total annual capital cost associated with serving each class. Finally, the total annualized capital cost is divided by the forecast number of customers in each class to determine each class' average marginal SRM cost. Table 1 shows the resulting annualized marginal capital costs.

TABLE 1
CUSTOMER-RELATED LRMC – CAPITAL COSTS

Customer Class	Rental-Method Customer Cost (2013 $/customer)
Residential	$201
Core Commercial/Industrial	$285
Natural Gas Vehicle	$1,113
Noncore Commercial/Industrial	$4,471
Small Electric Generation	$3,486
Large Electric Generation	$6,364

B. Fully Loaded Customer-Related LRMC

The total marginal customer costs for the six SDG&E customer classes are provided in Table 2. They are the result of combining the expense-related O&M loaders, which are discussed in Section VI, with the capital related costs from Table 1. The noncore customer classes post significantly higher marginal costs per customer than the core customer classes. This is expected since noncore customers have much higher gas service demands, and require larger and more specialized metering and service facilities compared with core customers.

TABLE 2
CUSTOMER-RELATED LONG RUN MARGINAL COSTS
(2013 $/customer)

Customer Class	Annualized Capital Cost	Expense-Related O&M				Total $/Customer
		Direct	M&S	A&G	General Plant	
Residential	$201	$44	$0.2	$14	$5	$263
Core Commercial/Industrial	$285	$96	$0.4	$30	$10	$422
Natural Gas Vehicle	$1,113	$356	$1	$109	$38	$1,618
Noncore Commercial/Industrial	$4,471	$3,999	$15	$1,227	$421	$10,133
Small Electric Generation	$3,486	$3,518	$13	$1,079	$371	$8,467
Large Electric Generation	$6,364	$4,201	$16	$1,289	$443	$12,311

V. DISTRIBUTION DEMAND-RELATED MARGINAL COSTS

Demand-related marginal costs are calculated for both the medium pressure (MPD) and high pressure (HPD) distribution systems. Separate marginal costs are calculated for the MPD and HPD systems because the two systems perform different functions. HPD investments are generally in pipelines that supply gas at a maximum allowable operating pressure of greater than 60 pounds per square inch gauge (psig), and are 10 inches in diameter or less. The MPD pipeline investments are generally in those pipelines at maximum allowable operating pressures of 60 psig and less.

A. Marginal Capital Costs

Consistent with the methodology adopted in D.92-12-058, ten years of historical (2001-2010) and five years of forecasted (2011-2015) distribution plant investments and marginal demand measures are utilized in this LRMC study. The historical period investments are provided by the SDG&E Gas Distribution Engineering Department from an analysis of accounting data for MPD and HPD capital investments. The forecasted investments are from the same department's capital budget forecast. The marginal demand measures are based on an analysis of peak-day throughput on the two distribution systems. The consolidated Demand Forecast, including peak-day load by market segment, is discussed in the testimony and workpapers of Mr. Wetzel.

Linear regression is used to determine the marginal capital costs of the MPD and HPD systems. This method plots the cumulative incremental investment as the dependent variable against the cumulative incremental changes in peak-day demand, which is the independent variable. The slope of the best-fit line is taken to be the marginal capital cost. This capital cost is then annualized by using a weighted-average RECC factor applicable to demand-related distribution pipeline investments. Charts 1 and 2 on the following pages depict the linear regression analysis in graphical form.

B. Fully Loaded Distribution LRMC

Loading factors for O&M, A&G, general plant and materials and supplies are applied to distribution marginal capital costs to determine the total marginal costs for the MPD and HPD systems. The O&M expenses and indirect cost loaders are developed in Section VI. The total marginal costs for the medium-pressure and high-pressure distribution systems are presented in Table 3 and Table 4.

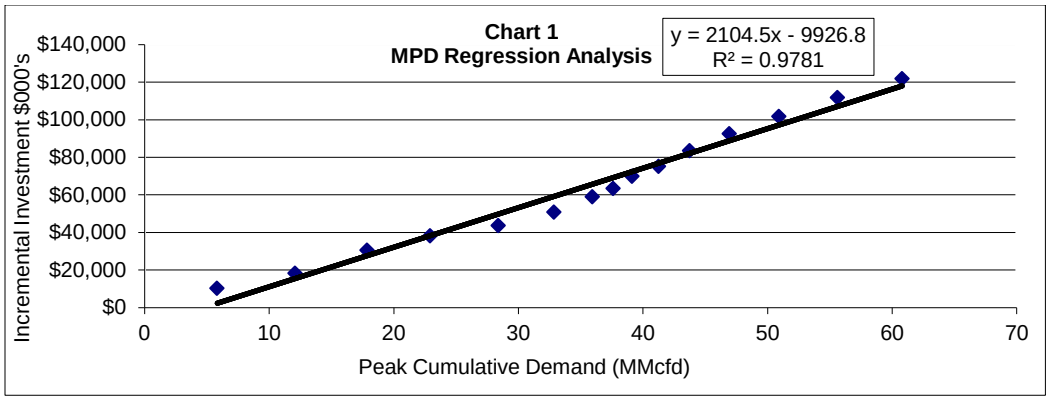

TABLE 3 MEDIUM-PRESSURE DISTRIBUTION LRMC (2013 $/Mcf MPD peak-day)		
	Marginal Investment Cost	$2,104.47
x	RECC Factor	8.73%
=	Annualized Investment Cost	$183.69
	Expense-Related	
+	O&M Cost	$19.01
+	A&G Cost	$5.83
+	General / Common Plant Cost	$2.00
+	M&S Cost	$0.46
=	**Total Marginal Cost**	$211.00

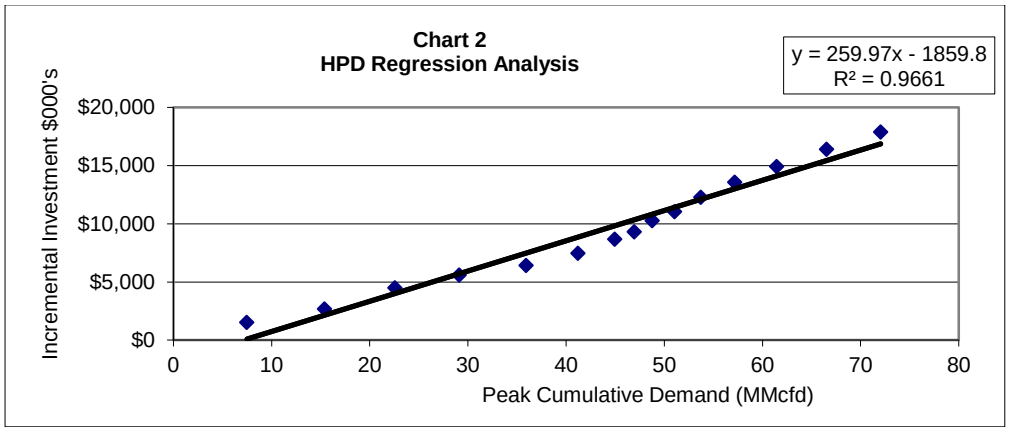

TABLE 4 HIGH-PRESSURE DISTRIBUTION LRMC (2013 $/Mcf HPD peak-day)		
	Marginal Investment Cost	$259.97
x	RECC Factor	8.73%
=	Annualized Investment Cost	$22.69
	Expense-Related	
+	O&M Cost	$0.77
+	A&G Cost	$0.23
+	General / Common Plant Cost	$0.08
+	M&S Cost	$0.06
=	**Total Marginal Cost**	$23.84

VI. MARGINAL COST ESTIMATION FACTORS

A. Real Economic Carrying Charges

In D.92-12-058, the Commission adopted the use of Real Economic Carrying Charges in LRMC studies. Their purpose and usefulness are discussed in Section VI of the testimony of Mr. Lenart. A summary of RECC factors used in this LRMC study for SDG&E is shown in Table 5.

TABLE 5 REAL ECONCOMIC CARRYING CHARGE FACTORS	
Cost Type	RECC %
Meters and Regulators	9.73%
Meter/Regulator Installation	8.98%
Service Line Pipe	8.79%
Weighted-Average Distribution	8.73%
Materials and Supplies	13.72%
Weighted-Average General/Common Plant	10.29%

B. Marginal Direct O&M Costs

Marginal direct O&M costs consist of both distribution and customer services expenses. Distribution O&M expenses are accounted for in FERC Accounts 870-894 of SDG&E's Annual Report ("Annual Report") to the Commission. They are allocated to both the customer cost as

well as the MPD and HPD functions. The expenses reflect costs associated with the maintenance of customer's meters, regulators, and service lines as well as distribution main. Customer services expenses are accounted for in the Annual Report in FERC Accounts 901-905 and 907-910. They are allocated entirely to the customer cost function. These expenses are associated with responding to customer service field orders and, generally, operating and maintaining service lines, meters and house regulators.

1. Distribution O&M Expenses

Distribution expense-related O&M is assigned to market segments by classifying the costs as either customer-related or demand-related. Customer-related expenses are allocated entirely to the customer cost function. The demand-related expenses are allocated between the HPD, MPD, and customer cost functions predominately based on pipeline mileage as of December 31, 2010. The SDG&E Gas Distribution Engineering Department identifies the marginal portion of each of FERC Accounts 870-894.

Once the distribution O&M expenses are functionalized, they are then allocated in two ways. Customer-related distribution O&M is allocated to the customer classes using the effective percentage of total annualized SRM investment costs. The resulting allocation of distribution O&M expenses to customer classes is combined with customer services O&M expenses discussed in the next section, and then divided by the number of customers in each class to determine a per customer direct O&M expense loader. MPD and HPD O&M expenses are divided by the peak-day demand of each system to determine their respective direct O&M expense loaders. A summary of direct distribution O&M expenses by market segment is presented in Table 6.

2. Customer Services O&M Expenses

Customer Services expenses in FERC Accounts 901-905 and 907-910 are functionalized entirely as customer cost. These costs include meter reading, customer services, credit collections, and billing services, and are allocated to customer classes in three steps. First, Customer Services marginal O&M expenses are classified into customer operational activities. Expenses by customer services department are then assigned to one of these operational activities. Finally, these expenses are allocated to customer classes based on either the operational activity performed or the market segment supported.

Once customer services costs are allocated to the customer classes, they are combined with Distribution O&M costs (as described in the previous section) in order to develop O&M loaders. The updated Distribution and Customer Accounts O&M costs as well as the resulting cost loaders are shown in Table 6.

TABLE 6
CUSTOMER-RELATED DIRECT MARGINAL O&M EXPENSES
(2013 $)

Customer Class	870-894 $000	901-910 $000	Customers per Class	Direct O&M $/Customer
Residential	$34,412	$1,677	819,482	$44
Core Commercial/Industrial	$2,635	$67	28,070	$96
Natural Gas Vehicle	$16	$0.1	44	$356
Noncore Commercial/Industrial	$109	$127	59	$3,999
Small Electric Generation	$57	$105	46	$3,518
Large Electric Generation	$44	$40	20	$4,201
Distribution Function	**870-894 $000**	**901-910 $000**	**Peak-day Load (Mcfd)**	**Direct O&M $/mcfd**
Medium-Pressure	$7,044	$0	370,492	$19.01
High-Pressure	$307	$0	401,008	$0.77

C. Marginal Loading Factors

SDG&E derives loading factors for marginal cost investments using the same methodology included in the 2009 BCAP application. The loading factors are for costs related to Administrative and General (A&G) expenses, General Plant (GP), and Materials and Supplies (M&S).

1. A&G Loading Factor

Marginal A&G expenses and payroll taxes are combined into a single loading factor. The recorded year 2010 A&G expenses from the Annual Report are classified as marginal and non-marginal by account. As shown in Table 7, the A&G expenses and payroll tax loader is 30.68%. The A&G loading factor is calculated as a percentage of total O&M (less A&G), and then multiplied by the direct O&M unit cost for each function.

TABLE 7
A&G LOADING FACTOR

	Account Description	Marginal Costs $ 000s
	A&G Expenses	$23,667
+	Payroll Taxes	$4,344
=	Total A&G with Payroll Taxes	$28,011
/	Total O&M Expenses excluding A&G	$91,308
=	A&G Loading Factor	30.68%

2. General Plant Loading Factor

General plant includes structures and improvements, office furniture and equipment, computer applications and equipment, shop and garage equipment, and communication equipment, as well as plant shared between SDG&E electric and gas operations allocated to the gas function. The recorded year 2010 General Plant total is multiplied by the weighted-average RECC factor of 10.29% to obtain an annualized general plant of $16.9 million. The general

plant loading factor is then determined by dividing annualized general plant by total O&M expenses. Table 8 shows the derivation of the General Plant Loading Factor to be 10.54%.

TABLE 8
GENERAL PLANT LOADING FACTOR

	Account Description	2010 Recorded Costs $ 000s
	Total General Plant	$164,603
x	Average General Plant RECC	10.29%
=	Annualized General Plant	$16,930
/	Total O&M Expenses	$160,616
=	General Plant Loading Factor	10.54%

3. M&S Loading Factor

M&S includes those materials in stock for use in company operations. Examples of M&S items include pipe, valves, fittings, and safety equipment. Recorded year 2010 M&S costs of $2.9 million are allocated to the functions based on percentage of gross plant in each functional category and then multiplied by an RECC factor of 13.72% to obtain annualized M&S costs. M&S costs allocated to the customer cost function are further allocated to the customer classes at the same relative percentage as direct O&M. M&S loaders are then derived by dividing allocated M&S costs by the number of customers in each class. For the distribution functions, allocated M&S costs are divided by peak-day load in order to determine the loader amounts. The resulting M&S loading costs by customer class and function are presented in Table 9.

TABLE 9
M&S LOADING FACTORS
(2013 $)

Customer Class	Allocated M&S	Customers per Class	M&S Loader $/Customer
Residential	$135,609	819,482	$0.17
Core Commercial/Industrial	$10,152	28,070	$0.36
Natural Gas Vehicle	$59	44	$1.34
Noncore Commercial/Industrial	$887	59	$15.03
Small Electric Generation	$608	46	$13.22
Large Electric Generation	$316	20	$15.78
Distribution Function	**Allocated M&S**	**Peak-day Load (Mcfd)**	**M&S Loader $/Mcfd**
Medium-Pressure	$171,927	370,492	$0.46
High-Pressure	$25,204	401,008	$0.06

VII. ALLOCATED BASE MARGIN

Upon completing the LRMC unit cost studies, SDG&E allocates costs to each function using the appropriate Marginal Demand Measure (MDM). Each MDM reflects the forecast annual average for the 2013 – 2015 TCAP period, as presented by Mr. Wetzel. Total customer costs are determined by multiplying each class' LRMC by the number of customers in each class. MPD and HPD costs are determined by multiplying each function's LRMC by the corresponding peak-day demand. This process is detailed in Tables 10a and 10b.

TABLE 10a UNSCALED LONG RUN MARGINAL COST CUSTOMER COST			
Customer Class	Customer LRMC $/customer	Customer Count	Customer Cost $000
Residential	$263	850,344	$223,692
Core C/I	$422	30,423	$12,826
NGV	$1,618	32	$51
Total Core			$236,570
Noncore C/I	$10,133	63	$638
Small EG	$9,282	52	$483
Large EG	$9,282	14	$130
Total Noncore			$1,251
Total SDG&E			**$237,822**

TABLE 10b UNSCALED LONG RUN MARGINAL COST DISTRIBUTION COSTS						
Customer Class	MPD LRMC $/Mcfd	MPD Peak-Day (Mcfd)	MPD Revenues $000	HPD LRMC $/Mcfd	HPD Peak-Day (Mcfd)	HPD Revenues $000
Residential	$211	274,812	$57,987	$24	274,940	$6,553
Core C/I	$211	84,150	$17,756	$24	86,580	$2,064
NGV	$211	3,159	$667	$24	3,251	$77
Total Core			$76,409			$8,694
Noncore C/I	$211	6,579	$1,388	$24	9,004	$215
Small EG	$211	1,871	$395	$24	4,978	$119
Large EG	$211	2,001	$422	$24	21,189	$505
Total Noncore			$2,205			$838
Total SDG&E			**$78,614**			**$9,533**

In D.92-12-058, the Commission stated that "marginal cost revenues need to be scaled to the embedded-based authorized revenue requirement under our ratemaking procedures." The current SDG&E gas base margin for transportation rates effective January 1, 2012 is $262 million, and this is the revenue requirement used to determine the scalar. The scalar adjusts allocated marginal costs to the authorized base margin, excluding costs directly assigned to the

Transmission ($31 million) and NGV Public Access ($181 thousand) functions. The embedded cost of transmission is from the testimony of Ms. Fung, and the NGV public access station cost is from the testimony of Mr. Bonnett. In this TCAP, marginal costs are scaled at a rate of 71% in order to reconcile to the adjusted base margin of $230 million. This process is shown in Table 11. Finally, scaled LRMC costs are added to the Transmission and NGV Public Access costs to determine the fully cost-based allocation of authorized gas base margin.[1] This is presented in Table 12.

TABLE 11
LONG RUN MARGINAL COST SCALED CUSTOMER AND DISTRIBUTION COSTS
$ 000

Customer Class	Customer Cost	+ MPD	+ HPD	= Unscaled LRMC	x Scalar	= Scaled LRMC
Residential	$223,692	$57,987	$6,553	$288,232	71%	$203,437
Core C/I	$12,826	$17,756	$2,064	$32,646	71%	$23,042
NGV	$51	$667	$77	$795	71%	$561
Total Core	$236,570	$76,409	$8,694	$321,674	71%	$227,041
Noncore C/I	$638	$1,388	$215	$2,241	71%	$1,582
Small EG	$483	$395	$119	$997	71%	$703
Large EG	$130	$422	$505	$1,057	71%	$746
Total Noncore	$1,251	$2,205	$838	$4,295	71%	$3,031
Total SDG&E	**$237,822**	**$78,614**	**$9,533**	**$325,969**	**71%**	**$230,072**

[1] Per the testimony of Ms. Fung, the SDG&E transmission system is 100% backbone. For the purposes of this testimony, SDG&E's $31 million in backbone transmission costs are allocated to the Backbone Transmission Service rate class. These costs will be incorporated in System Integration in the testimony of Mr. Bonnett, which unbundles part of the combined SoCalGas/SDG&E transmission system into the Backbone Transmission System tariff, with the remaining transmission costs being allocated to the local transmission function and, ultimately, back to the customer classes.

TABLE 12 ALLOCATION OF BASE MARGIN $ 000							
Customer Class	Scaled LRMC	+	Backbone Transmission	+	NGV Public Access	=	Unadjusted Allocated Base Margin
Residential	$203,437		$0		$0		$203,437
Core C/I	$23,042		$0		$0		$23,042
NGV	$561		$0		$181		$742
Total Core	$227,041		$0		$181		$227,221
Noncore C/I	$1,582		$0		$0		$1,582
Small EG	$703		$0		$0		$703
Large EG	$746		$0		$0		$746
Total Noncore	$3,031		$0		$0		$3,031
Backbone Transmission	$0		$31,473		$0		$31,473
Total SDG&E	**$230,072**		**$31,473**		**$181**		**$261,726**

VIII. BASE MARGIN ADJUSTMENTS AND PHASE-OUT PERIOD

In Section IX of the testimony of Mr. Lenart, SoCalGas and SDG&E present transition adjustments to their cost allocation studies. Along with a proposed phase-out period, these adjustments are being made with the expectation of returning to fully cost-based rates by the end of the phase-out period. Table 13 shows the allocation of SDG&E's gas base margin that results from the adjustments proposed by Mr. Lenart.

TABLE 13
COST ALLOCATION COMPARISON
$ 000

Customer Class	Adjusted Allocation of Base Margin	% Total	Current Allocation of Base Margin	% Total
Residential	$195,437	74.7%	$188,029	71.8%
Core C/I	$31,042	11.9%	$26,856	10.3%
NGV	$742	0.3%	$380	0.1%
Total Core	$227,221	86.8%	$215,265	82.2%
Noncore C/I	$1,582	0.6%	$3,047	1.2%
Small EG	$703	0.3%	$1,538	0.6%
Large EG	$746	0.3%	$971	0.4%
Total Noncore	$3,031	1.2%	$5,555	2.1%
Backbone Transmission	$31,473	12.0%	$40,905	15.6%
Total SDG&E	**$261,726**		**$261,726**	

This concludes my revised updated prepared direct testimony.