

Application No.: A.03-09-

Exhibit No.: _____

Date: September 3, 2003

Witness: Herbert S. Emrich

**PREPARED DIRECT TESTIMONY OF
HERBERT S. EMMRICH
SOUTHERN CALIFORNIA GAS COMPANY**

(Embedded Cost Study)

September 3, 2003

2005 BIENNIAL COST ALLOCATION PROCEEDING

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million of storage-related costs were removed from Base Margin consistent with SoCalGas' FRCA filing resulting in \$1,389 million to be allocated in the ECS.

The major cost components are Operations and Maintenance expenses of \$707 million, capital-related costs (return, depreciation, and income and property taxes) of \$598 million, payroll taxes of \$23 million, Franchise and Uncollectible expenses of \$26 million, a miscellaneous revenue credit reducing rates by \$43 million, and a \$80 million, or 6.1%, reconciliation factor to account for customer growth, inflation and customer productivity benefits for the year 2003.

Table 1

Distribution and Transmission Base Margin
Components
(\$ Millions)

Ln.	Item	\$ millions
	<u>O&M</u>	
1	2002 Gas O&M	2,090.123
2	<u>Less Gas Costs</u>	<u>(1,190.088)</u>
3	Subtotal	900.035
4	Less PBR Exclusions	(93.718)
5	Less Franchise Fees & Uncollectibles	(34.286)
6	<u>Other Adjustments</u>	<u>(65.313)</u>
7	Subtotal Embedded O&M in ECS	706.719
8	<u>Capital-Related Costs</u>	
9	Return	192.289
10	Depreciation	236.407
11	<u>Taxes</u>	<u>168.890</u>
12	Subtotal Capital-Related Costs	597.585
13	Payroll Taxes	22.717
14	Miscellaneous Revenues	(43.051)
15	<u>F&U Expense</u>	<u>25.938</u>
16	Total Embedded Costs 2002	1,309.908
17	<u>Reconciliation (Cust. Growth, Inflation, Productivity)</u>	<u>79.527</u>
18	<u>Authorized 2003 Base Margin</u>	<u>1,389.435</u>

(Note: The \$1,389 million Authorized 2003 Base Margin excludes \$21 million in customer benefits related to PBR productivity and merger savings.)

2. Classification of Embedded Costs

The classification of these embedded costs (EC) into: customer-; distribution demand-; transmission-; and, non-DSM Customer Services and Information-related costs are shown in Table 2 below. Of the total \$1,389 million 2003 authorized Base Margin costs, \$830 million were calculated to be customer-related, \$365 million distribution demand-related, \$155 million

transmission demand related and \$40 million Non-Energy Efficiency (EE) Customer Service and Information-related. Customers were credited for \$43 million in miscellaneous revenues collected mainly through the service establishment charge, commercial parts program and other revenue generating services.

Table 2
Classification of Embedded Costs
(\$Millions)

Ln	Function	O&M Expense & Payroll Taxes (a)	Capital Related Costs (b)	Total Embedded Costs (c)	Misc. Revenues (d)	F&U Plus Recon- ciliation (e)	Total (f)
1	Customer-Related	534.853	266.613	801.466	(34.780)	62.976	829.661
2	Distribution						
3	High Pressure	9.139	35.872	45.011	(0.175)	3.683	48.519
4	Medium Pressure	83.931	209.643	293.574	(1.218)	24.014	316.370
5	Subtotal	93.070	245.515	338.585	(1.393)	27.697	364.889
6	Transmission	66.702	83.388	150.090	(6.652)	11.782	155.220
7	Non-EE Cust Svc & Info	34.811	2.069	36.880	(0.225)	3.011	39.666
8	Total	729.436	597.585	1,327.020	(43.051)	105.465	1,389.435

These revenues and the miscellaneous revenues crediting method are discussed in more detail below. (Note: All Storage, and 3.6 percent of: General Plant; A&G; payroll and property taxes; and gas commodity-related costs were excluded from the ECS per SoCalGas' FRCA filing.)

3. Allocation of Distribution and Transmission Expenses by Customer Class

Table 3 below shows the embedded cost-based allocation of Distribution and Transmission-related Base Margin costs for each of SoCalGas' customer classes. Of the total \$1,389 million allocated in the ECS, \$1,069 million, or 77 percent, is allocated to the residential, \$178 million, or 12.8 percent, to core Commercial and Industrial customers, \$154,000 to the Gas Air Conditioning class, \$2.8 million to the Gas Engine customer class and \$5.1 million to the Natural Gas Vehicle class of customers. The \$1,256 million total allocation to the core class represents 90.4 percent of the total customer-related distribution and transmission costs allocated.

1 Non-core customers were allocated \$135 million, or 9.6 percent, of total authorized Base
 2 Margin costs. Of this total, retail non-core customers were allocated \$105 million in distribution
 3 Base Margin costs. The largest portion of non-core customer costs, \$55 million, was allocated to
 4 noncore Commercial and Industrial customers. \$50 million was allocated to the Electric
 5 Generation class, \$28 million to Wholesale customers, and \$1 million to one international
 6 customer, DGN. Enhanced Oil Recovery revenues are then credited to all customers on a
 7 percent of base margin basis to develop final EC-based rates as shown by SoCalGas witness
 8 Steve Lango in his testimony.

9
 10 **Table 3**
 11 **Distribution and Transmission Base Margin By Customer Class**
 12 **(\$ Millions)**

Ln.	Customer Class	Proposed Embedded Cost Allocation	Average Yr. MDth	Cents/Therm	Proposed Embedded Cost Allocation Percent
1	Residential	1,068.162	274,589	38.900	76.88%
2	G-10	177.978	96,985	18.351	12.81%
3	Gas A/C	0.155	191	8.124	0.01%
4	Gas engine	2.845	2,794	10.183	0.20%
5	NGV Total	8.354	7,888	10.592	0.60%
6	NGV Uncompressed	7.114	7,714	9.222	0.51%
7	NGV Compression Adder	1.240	174	71.446	0.09%
8	NGV Compressed Rate			80.668	
9	Subtotal core	1,257.495	382,446	32.880	90.50%
10	G-30	55.249	127,096	4.347	3.98%
11	Electric Generation Total	51.041	205,032	2.489	3.67%
12	Small EG	5.257	4,723	11.131	0.38%
13	Large EG	45.783	200,309	2.286	3.30%
14	Subtotal retail noncore	106.289	332,128	3.200	7.65%
15	Long Beach Gas	2.199	10,238	2.148	0.16%
16	SDG&E	17.613	95,211	1.850	1.27%
17	Southwest Gas	2.350	8,326	2.823	0.17%
18	City of Vernon	2.458	9,875	2.489	0.18%
19	Subtotal wholesale	24.620	123,650	1.991	1.77%
20	DGN	1.031	4,729	2.180	0.07%
21	Unbundled storage	-			0.00%
22	Subtotal noncore	131.940	460,507	2.865	9.50%
23	Total	1,389.435	842,953	16.483	100.00%

1 **III. Embedded Cost Study Approach**

2
3 The embedded cost allocation principles followed by SoCalGas in conducting the ECS
4 are generally consistent with the functionalization, classification and allocation principles
5 formulated by the American Gas Association as presented in the *Gas Rate Fundamentals*, Fourth
6 Edition, 1987. The underlying principle of conducting embedded cost studies is to account for
7 costs in functional categories, Federal Energy Regulatory Commission (“FERC”) Accounts,
8 classify them into customer- or demand-related costs and then allocate the costs incurred in a
9 particular year to specific -customer classes based on cost causality. In the case of common
10 costs, i.e. costs of facilities and services shared by different customer classes such as distribution
11 and transmission, and general plant costs, allocation methodologies were used that allocate these
12 costs among customer classes based on marginal demand measures and allocation factors that
13 reflect cost causality, respectively.

14 SoCalGas employed the standard approach used in conducting cost allocation studies:
15 functionalization and classification followed by allocation of costs to customer classes based on
16 cost causality. In the first step, all of SoCalGas’ year 2002 costs were functionalized into the
17 following FERC account categories: Underground Storage; Transmission; Distribution;
18 Customer Accounts; Non-Energy Efficiency Customer Services and Information; and
19 Administrative and General (A&G) expenses.

20 Costs associated with storage, and 3.6% of A&G, payroll taxes and General Plant capital-
21 related costs associated with Storage, were excluded from the ECS based on SoCalGas’ FRCA
22 implementation filing, A.03-06-040 and the GIR decision, D.01-12-018. In addition to the
23 exclusion of underground storage costs, gas acquisition costs were excluded from this study
24 because these costs are included in gas commodity costs in the form of a \$0.0201/Dth brokerage
25 fee added to the Core Weighted Average Cost of Gas (WACOG) per D.01-12-018.

26 1. Base Margin Costs Net of Firm Rights for California (FRCA) Filing Exclusions

27 All base margin costs were accounted for under the standard FERC gas account
28 categories. The total authorized Base Margin, net of FRCA exclusions, for 2002 was \$1,373

1 million. These 2002 Base Margin costs were then escalated by SoCalGas' PBR cost escalation
2 formula to calculate the 2003 authorized Base Margin costs, net of FRCA Storage exclusions, to
3 \$1,389 million. The calculation of Base Margin costs net of FRCA exclusions is described in
4 more detail below.

5 SoCalGas' base margin for 2003 is set by the Performance Based Ratemaking (PBR)
6 Decision (D.97-07-054) formula. The basic formula includes annual increases in Base Margin to
7 cover higher costs associated with customer growth and inflation minus an annual productivity
8 benefit to customers. Authorized Year 2003 base margin costs, net of \$82 million of storage-
9 related FRCA exclusions, totaling \$1,389 million were then allocated to customer classes. The
10 2003 base margin total includes an adjustment to reflect the Market Indexed Capital Adjustment
11 Mechanism (MICAM) filing adopted in AL 3193-A which reduced base margin by \$10.514
12 million to reflect reduced cost of capital expenses. (Note: Since \$2.185 million of Aliso Canyon
13 Storage Field costs have already been excluded from Base Margin, the net total Storage cost
14 reduction from Base Margin was \$79.637 million (\$81.822 million less \$2.185 million equals
15 \$79.637 million).

16 2. Base Margin True-Up Factor

17 To start the ECS, the year 2002 \$1,310 million of actual costs to provide customer-
18 related, distribution and transmission service were allocated among SoCalGas' customer classes
19 based on the costs incurred to serve those customers. The 2002 total actual costs of \$1,310
20 million was then trued up by a 6.1 percent reconciliation factor to recover the total \$1,389
21 million 2003 Base Margin costs authorized under the PBR formula minus all FRCA exclusions
22 (i.e., storage and storage-related A&G and General Plant capital-related expenses). The
23 reconciliation factor was applied equally across all cost categories to recover all 2003 authorized
24 base margin expenses. The \$79 million reconciliation amount accounts for authorized cost
25 increases related to one year of customer growth and one year of inflation, minus a 2.5 percent
26 productivity factor as proscribed by the PBR cost escalation formula, to scale 2002 actual costs,
27 net of storage-related costs and other non-base margin exclusions, up to the \$1,389 million 2003
28 authorized Base Margin.

1 3. Treatment of Underground Storage Costs

2 Underground storage costs of \$71.6 million and \$3.3 million of variable costs, plus
3 2.44% in-kind fuel costs for injection and withdrawal, were escalated by the PBR formula, as
4 approved in D. 97-07-054, to \$81.822 million. These costs were unbundled and removed from
5 2003 Base Margin on an embedded cost basis consistent with D. 01-12-018. As part of the
6 Comprehensive Settlement Agreement (CSA) adopted by the Commission with modifications in
7 D. 01-12-018, the calculation of the underground storage costs unbundled includes an allocation
8 of 3.6% of common costs (A&G and common plant), 3.6% of payroll taxes and 3.6 % of
9 property taxes to storage. Therefore, the ECS analyzed and allocated only customer-, Non EE-
10 Customer Service and Information-, distribution-, and transmission-related Base Margin costs to
11 SoCalGas' customer classes. All underground storage costs and associated A&G and General
12 Plant capital-related costs were allocated to customers classes based on D. 01-12-018.

11 4. Capital –Related Costs of Service

12 The Net Book Value (NBV) of SoCalGas' total Gas Plant in Service was \$2,563 million
13 at year end 2002 as shown in Table 4. Intangible net plant in Service of \$0.575 million was
14 recorded in FERC accounts 301 and 302. Underground storage net plant was recorded in FERC
15 accounts 350 through 363 and totaled \$125 million. Transmission net plant was recorded in
16 FERC accounts 365 through 371 and totaled \$349 million. Distribution net plant was recorded
17 in FERC accounts 374 through 387 and totaled \$1,837 million. General Plant was recorded in
18 FERC accounts 389 through 399 and totaled \$251 million. As noted above, all storage and 3.6
19 percent of General Plant costs associated with storage was excluded from the ECS.

20 The utilities' common and preferred shareholders and bondholders finance investments in
21 a utility's capital plant. Ratepayers pay for all capital-related carrying costs of service in rates.
22 These annual capital-related costs are comprised of: depreciation and amortization expenses;
23 return on investment to common and preferred shareholders; cost of long-term debt financed
24 through the issuance of utility bonds; state and federal income taxes; and property taxes. Utility
25 investors are allowed to earn a return on rate base, i.e., investments in utility plant minus
26 accumulated depreciation, and to recover their full investment costs through an annual
27 depreciation charge over the book life of the investment. The annual depreciation charge of
28 utility plant is specific to the type of facility or equipment in service. There are different

depreciable lives for plant categories such as: distribution mains; house lines; meters; meter set
assemblies; regulators; and general plant such as buildings and computer equipment. The
straight-line yearly depreciation charge, by plant category, is included in the capital-related cost
of service and is recovered in rates charged to customers. SoCalGas' Plant Accounting
Department provided the yearly and total accumulated depreciation by FERC account category.
Total Underground Storage, Transmission, Distribution, and General Plant depreciation was
\$276 million in year 2002. Underground Storage Amortization Expenses of Land and Land
Rights, FERC account 350, totaled \$219,000 and General Plant reassignments totaled \$1.6
million in 2002. The Investment, Accumulated Depreciation, NBV, Depreciation and
Amortization and reassignments, by FERC account, are shown in Table 4 below.

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Table 4



SOUTHERN CALIFORNIA GAS COMPANY
2002 Utility Gas Plant in Service
By FERC Account for FERC Form 2
(Thousands of Dollars)

ACCOUNT	ACCT NO.	As of December 31, 2002			For the Year Ended 2002		
		INVESTMENT	ACCUM DEP	NET BOOK VALUE	DEPRECIATION EXPENSE	AMORTIZATION EXPENSE	REASSIGNMENTS
Intangible							
	301	76	-	76	-		
	302	499	-	499	-		
Total Intangible		575	-	575	-		
Underground Storage							
	350	22,654	(15,063)	7,591	220	219	
	351	22,225	(13,894)	8,330	664		
	352	156,646	(101,583)	55,063	5,031		
	353	76,776	(77,154)	(378)	3,550		
	354	89,425	(61,266)	28,159	3,167		
	355	1,143	(1,220)	(77)	24		
	356	68,353	(46,329)	22,025	3,274		
	357	5,548	(1,524)	4,024	166		
Montebello *					5,595		
Total Underground Storage		442,770	(318,033)	124,736	21,690	219	
Transmission							
	365	22,352	(10,189)	12,164	464		
	366	25,765	(17,894)	7,872	654		
	367	667,368	(419,967)	247,400	19,438		
	368	141,817	(76,290)	65,527	5,173		
	369	38,198	(23,648)	14,550	1,021		
	371	2,240	(601)	1,639	144		
Total Transmission		897,741	(548,590)	349,151	26,893		
Distribution							
	374	30,245	(12)	30,233	-		
	375	126,790	(35,362)	91,428	4,940		
	376	2,204,271	(1,178,698)	1,025,573	76,235		
	378	44,297	(26,764)	17,533	2,579		
	380	1,598,493	(1,239,710)	358,783	74,737		
	381	321,504	(130,107)	191,397	11,645		
	382	214,211	(157,136)	57,074	10,481		
	383	95,663	(36,666)	58,997	3,488		
	387	19,345	(13,116)	6,229	1,556		
Total Distribution		4,654,819	(2,817,573)	1,837,247	185,662		
General Plant							
	389	1,489	-	1,489	-		
	390	85,459	(56,521)	28,938	5,065		
	391	224,092	(94,490)	129,602	23,043		
	392	1,537	(1,338)	199	226		1
	393	957	(751)	206	29		
	394	41,896	(16,427)	25,469	337		1,629
	395	6,692	(3,098)	3,594	330		
	396	95	1	96	-		7
	397	107,607	(53,744)	53,863	11,941		
	398	4,250	3,507	7,757	418		
Total General Plant		474,075	(222,861)	251,214	41,389		1,637
Total Utility Gas Plant In Service		6,469,980	(3,907,057)	2,562,923	275,635	219	1,637

Footnotes:

* Montebello assets are recorded in non-utility assets; however, depreciation is recorded as utility depreciation.

** Excluded Arco Cuyama Leased Line

*** Below is the breakdown for NGV Stations: (Dollars in thousands)

Investment	11,018
Accum Dep	4,571
Net Book Value	6,446
Depreciation Exp	954
FERC Account	387.20

5. Rate Base Components

Capital-related costs included in 2002 actual costs equal the 2002 annual authorized rate of return on rate base of 9.49 percent times authorized weighted average rate base. (Note: The authorized return for 2003 was reduced to 8.70 percent per AL 3199-A to reflect the PBR Market Capital Adjustment Mechanism. This reduction in authorized rate base is reflected in the \$1,389 million Base Margin total used in the ECS.) These capital-related costs are designed to cover the

1 investors' cost of capital, i.e. the cost of debt and equity, paid to bondholders and shareholders to
2 finance the investments made in utility plant and equipment. Rate base components include net
3 plant, materials and supplies, working capital, Construction Work In Progress (CWIP), deferred
4 taxes, and gains on sale of utility property as shown in Table 4.

5 First, SoCalGas' net utility plant in service was calculated by subtracting the annual
6 average total accumulated depreciation of \$3,813 million from the annual average \$6,403 million
7 plant in service in 2002. The average net utility Plant in Service in 2002 was \$2,590 million
8 ($\$6,403,475 - \$3,813,386 = \$2,590,089$). Net Plant in Service is the chief component of rate base
9 on which the utility's investors earn a rate of return.



10 Second, other capital-related items were added to Rate Base, such as: Non-Interest CWIP
11 at \$6 million; Materials and Supplies at \$11 million; Working Cash at \$26 million, Accumulated
12 Deferred Taxes-CIAC at \$4 million.

13 Third, authorized Rate Base was reduced by Customer Advances for Construction at
14 \$31.862 million; Deferred Revenue-ITCC at \$449,000; Aliso Gas Rights at \$210,000; Gain on
15 Sale of El Monte and Pasadena Bases at \$620,000; Other Gain on Sales at \$14 million; and
16 Accumulated Deferred Taxes-Plant at \$369 million. These reductions to Rate Base were made
17 to account for customer-funded and straight-line depreciation versus tax depreciation generated
18 sources of funds. The weighted average authorized rate base for SoCalGas in 2002 was \$2,220
19 million. From this total \$193 million of storage and storage-related General Plant was subtracted
20 from rate base consistent with FRCA exclusions leaving \$2,026 million of rate base to be
21 allocated to customers for distribution and transmission service.

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The 2002 annual average authorized rate base, minus storage-related rate base, of \$2,026 million was multiplied by the 2002 authorized 9.4903 percent return on investment. This rate of return was used to calculate the return-related capital costs of service for each investment category. The authorized after tax return on investment is comprised of the authorized return on common stock multiplied by the percent of common equity; plus, the authorized return on preferred stock multiplied by the authorized percent of preferred stock; plus, the authorized cost of long-term debt times the percent of long-term debt. For SoCalGas, the authorized return on rate base in 2002 was 9.4903 percent as shown in Table 6 below.

Table 5

 SOUTHERN CALIFORNIA GAS COMPANY Rate Base Components (Thousands of Dollars)		
		
Account Description	Balance Ending Dec 31, 2002	Weighted Average Balance as of Dec 31, 2002
Fixed Capital		
Plant In Service *	\$ 6,514,009	\$ 6,403,475
Work In Progress (Non-Interest Bearing)	7,994	6,384
Total Fixed Capital	6,522,003	6,409,859
Working Capital		
Material & Supplies	12,353	10,089
Working Cash	26,485	26,485
Total Working Capital	38,838	36,574
Other		
Customer Advances for Construction	(39,192)	(31,862)
Deferred Revenue - ITCC	(2,940)	(449)
Aliso Gas Rights	(210)	(210)
Gain on Sale - El Monte & Pasadena	(620)	(620)
Gain on Sale - Other	(14,754)	(14,724)
Total Other	(57,716)	(47,866)
Deduction for Reserves		
Accumulated Depreciation Reserve *	3,801,884	3,813,386
Accumulated Deferred Taxes - Plant *	373,701	368,881
Accumulated Deferred Taxes - CIAC	(7,454)	(3,704)
Accumulated Deferred Investment Tax Credits	649	705
Total Deductions for Reserves	4,268,780	4,179,268
Total	\$ 2,234,345	\$ 2,219,298
* Excluded Arco Cuyama Leased Line and Aliso Canyon Expansion		

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Table 7

State and Federal Income Taxes

(\$ Millions)

Preferred Stock ROI Component	8.221
Common Equity ROI Component	112.817
<u>Subtotal</u>	<u>121.038</u>
Tax Net-to-Gross Multiplier	1.68765
Grossed-up ROI Components	204.270
Income Taxes FIT & SIT	83.232
<u>Income Taxes FIT & SIT + Intercept</u>	<u>139.959</u>

In addition to these return and tax costs, book depreciation of \$252 million and ad valorem (property) taxes of \$29 million were recorded by SoCalGas in 2002. Total capital related costs, excluding storage-related and Franchise and Uncollectible expenses, were \$614 million in 2002. The totals are shown in Table 8 below.

Table 8

Capital-Related Cost Revenue Requirements Net of Storage

(\$ Millions)

Return on Investment	192.289
Book Depreciation	252.455
Ad Valorem Taxes	28.931
Income Taxes - FIT & SIT	139.959
<u>Subtotal Margin Excluding F&U</u>	<u>613.633</u>

The total \$614 million capital-related costs excludes costs associated with Storage and 3.6 percent of General Plant consistent with the FRCA filing.

8. Gas Operations and Maintenance Expenses

Gas Operations and Maintenance Expenses of \$900 million, including franchise fee costs, were recorded in FERC accounts 814 through 935 in 2002. These expenses cover costs related to: Underground Storage; Transmission; Distribution; Customer Accounts; Customer Services and Information; and Administrative and General Expenses. (Note: Gas Commodity expenses and gas acquisition-related costs of \$2,116 million, recorded in FERC accounts 800 through 813, are not included in this ECS. These expenses are included in the calculation of the Weighted

1 Average Cost of Gas (WACOG)). Underground Storage O&M expenses of \$60 million were
 2 recorded in FERC accounts 814 through 837. These Underground Storage expenses were
 3 excluded from the ECS per D.01-12-018. Transmission O&M expenses of \$43 million were
 4 recorded in FERC accounts 850 through 867. Distribution O&M expenses of \$217 million were
 5 recoded in FERC accounts 870 through 894. Gas Operations and Maintenance Expenses were
 6 further broken down into Customer Accounts Expenses of \$131 million in FERC accounts 901
 7 through 905, Customer Service and Information Expenses of \$81 million in FERC accounts 907
 8 through 910; and, Administrative and General Expenses of \$369 million in FERC accounts 920
 9 through 935. The total Gas Operation and Maintenance Expenses, excluding Gas Supply
 10 expenses and F&U, for 2002 were \$861 million as shown in FERC Form No. 2, pages 320
 11 through 325 and Table 9 below.

12 Table 9

13 SoCalGas' Operations and Maintenance Expenses
 14 (\$ Millions 2002)

15 FERC Functional Accounts	Total	Operations	Maintenance
16 Storage	59.521	47.395	12.126
17 Transmission	43.260	36.579	6.681
18 Distribution	216.541	156.841	59.700
19 Customer Accounts	131.328	131.328	0.000
20 Customer Services	80.684	80.684	0.000
21 Administrative and General	329.549	325.156	4.394
22 Total	860.883	777.983	82.901

23 *Note: \$39.151 million in Franchise Fee costs is not included in A&G. These costs are
 24 accounted for in the Franchise Fee and Uncollectables Charge of 2.0012% added
 25 to the WACOG and 1.5001% added to Wholesale core subscription service.

26 **IV. Functionalization and Classification of Operations and Maintenance (O&M)
 27 and Administrative and General (A&G) Expenses**

28 1. Distribution O&M Expenses

Distribution O&M Expenses included in FERC Accounts 870 through 894 totaled \$217 million in 2002. Of this total, \$199 million of Distribution O&M expenses were included in the ECS. This total excluded Hazardous Waste expenses since these costs are not included in Base

Margin. These distribution O&M expenses were then classified into customer, high- and medium-pressure-related costs by Distribution staff experts. Customer-related expenses are costs associated with operating and maintaining customer facilities such as: service lines, meters and house regulators as well as after-meter services. Demand-related distribution O&M expenses are costs associated with operations and maintenance of high- and medium-pressure distribution facilities, such as pipeline systems and regulating stations. Demand-related costs were assigned to the high and medium pressure category based on high pressure and medium pressure main footage in service. SoCalGas had 241 million feet of distribution mains in service in the beginning of 2002. Of this total, 7.9 percent was high pressure and 92.1 percent was medium pressure main. (See Table 26 for medium pressure and high-pressure distribution main footage.) The breakdown of Distribution O&M costs into functional categories is shown in Table 10 below.

Table 10
Functionalization and Classification of Distribution O&M Expenses
(\$Millions 2002)

Ln	Acct	Item	Customer Related	High Pressure	Medium Pressure	Total
1	870	Op-Supervision & Engineering	15.137	0.584	6.812	22.534
2	874	Op-Mains & Services Expenses	-	0.000	0.000	0.000
3	875	Op-Meas & Reg Station Exp Genrl	-	0.049	0.577	0.626
4	878	Op-Meter & House Regulator Exp	6.630	-	-	6.630
5	879	Op-Customer Installations Expenses	81.391	-	-	81.391
6	880	Op-Other Expenses	21.823	0.564	6.578	28.965
7	881	Op-Rents	0.048	0.001	0.010	0.059
8	885	Mnt-Supervision & Engineering	9.943	0.605	7.051	17.599
9	886	Mnt-Structures & Improvements	0.075	0.001	0.016	0.092
10	887	Mnt-Mains	4.984	0.997	11.621	17.602
11	889	Mnt-Meas & Reg Station Equip	-	0.123	1.435	1.558
12	892	Mnt-Services	14.551	0.235	2.737	17.523
13	893	Mnt-Meters & House Regulators	5.324	-	-	5.324
14	894	Mnt-Other Equipment	0.003	-	-	0.003
15		Total	159.909	3.160	36.837	199.906
16		Percent of total	80.0%	1.6%	18.4%	100.0%
17						
18		870 labor factor				7.8%
19		Payroll tax example for direct testimony.	1.191	0.046	0.536	1.773

2. Transmission O&M Expenses

Transmission O&M expenses of \$36 million were included in the ECS and classified as demand-related transmission expenses. Transmission O&M expenses are included in FERC Accounts 850 through 867. This total excluded \$6 million in Transmission compressor station fuel not included in Base Margin. The breakdown of Transmission O&M costs by FERC Account is shown in Table 11 below.

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Table 11

Functionalization of Transmission O&M Expenses

(\$ Millions 2002)

Ln	Acct	Item	Transmission
1	850	Op-Supervision & Engineering	10.262
2	851	Op-System Control & Load Dispatching	1.877
3	852	Op-Communication System Expenses	0.485
4	853	Op-Compressor Station Labor & Expenses	1.955
5	854	Op-Gas From Compressor Station Fuel	-
6	856	Op-Mains Expenses	3.389
7	857	Op-Measuring & Regulating Station Expenses	0.696
8	858	Op-Trans & Compression Of Gas By Other	0.002
9	859	Op-Other Expenses	4.035
10	860	Op-Rents	6.943
11	861	Mnt-Supervision & Engineering	-
12	862	Mnt-Structures & Improvements	0.084
13	863	Mnt-Mains	2.290
14	864	Mnt-Compressor Station Equipment	3.829
15	865	Mnt-Measuring & Regulating Station Equipment	0.359
16	867	Mnt-Other Equipment	0.119
17	Total		36.325

3. Functionalization, Classification and Allocation of Customer Accounts Expenses.

Customer Accounts Expenses are booked in FERC Accounts 901 through 905. Customer Accounts operations costs totaled \$131 million in 2002 as shown in Table 12 below. FERC Account 904, Uncollectible expenses, of \$4.9 million was excluded from the ECS and accounted for in the F&U charge calculated for the ECS. The F&U costs were accounted for in the ECS through a 1.0199 retail and a 1.0151 wholesale F&U gross-up factor respectively. California Alternative Rates for Energy (CARE) costs of \$2.3 million were excluded from FERC Account 901 because these costs are not included in Base Margin. Therefore a total of \$134 million was included in the ECS.

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Table 12
Customer Accounts O&M Expenses Functionalization
(\$ Millions 2002)

FERC Acct	Account Description	Recorded	Adjust.	Total in ECS
901	Cus Acct-Supervision	7.181	(2.294)	4.886
902	Cus Acct-Meter Reading Expenses	21.403	-	21.403
903	Cus Acct-Customer Records & Collections Exp	107.586	-	107.586
904	Cus Acct-Uncollectible Accounts	(4.866)	4.866	-
905	Cus Acct-Misc Customer Accounts Exp	0.025	-	0.025
	Totals	131.328	2.572	133.900

The resulting \$134 million was classified as customer-related costs and allocated to customer classes as shown in the “allocation method” column in Table 13 below. Most costs were allocated to customer classes based on the number of accounts and volume of customer accounts-related field orders associated with a particular function. Customer Contact Center costs of \$25.1 million were allocated to customer classes based on the number of accounts weighted by recorded call volume associated with each customer class. Meter reading costs of \$22 million were allocated based on the estimated meter reading time and number of meters in each customer class. Bill distribution costs of \$20.7 million were allocated based on the number of accounts in each customer class. Supervision and Staff Support costs of \$16 million were allocated by the same allocator used to allocate the activities that they supervised and supported. Billing system maintenance and development costs of \$25 million followed the allocator of the activities they supported. Collections costs of \$9 million were allocated by the number of collect and close orders in each customer class. Branch Office costs of \$6 million were allocated to each customer class based on the number of accounts and weighted field order volume. Core and non-core exceptional billing transaction costs of \$5 million were allocated according to the number of exceptional bills issued, field order volume and number of accounts. Remittance processing costs of \$6 million and authorized payment agencies costs of \$2 million were allocated based on the number of accounts in each customer class.

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Table 13
Customer Accounts Expenses
(FERC Accounts 901, 902, 903, 905)

Function	2002 Costs	Allocator
Call Center	\$ 25,065,315	Number of accounts and weighted call volume
Meter Reading	\$ 21,883,455	Estimated weighted read time and number of meters
Bill Distribution	\$ 20,732,352	Number of accounts
Supervision and Staff Support	\$ 15,879,026	Followed the allocator of the activities supported
Billing System Maintenance & Enhancements	\$ 24,863,492	Followed the allocator of the activities supported
Collections	\$ 8,512,820	Number of collect and close orders
Branch Office	\$ 5,850,970	Number of accounts and weighted field order volume
Core and Non-Core Billing	\$ 5,311,651	Number of exception billing transactions, field order volume and number of accounts
Remittance Processing	\$ 3,984,302	Number of accounts
Authorized Payment Agencies	\$ 1,926,669	Number of accounts

Most Customer Accounts costs were allocated to customer classes based on the number of accounts in each customer class. Of these Customer Account costs 97.6 percent were assigned to core customers and the remaining 2.3 percent to non-core customers. The breakdown by customer class is shown in Table 14 below.

Table 14
Customer Accounts Costs by Customer Class
Customer Accounts Cost Allocation (\$ Millions 2002)

FERC Account	Residential	Core C&I	Other Core	Total Core	Noncore C&I	Elect. Gen	Retail Noncore	Wholesale	Total
901	1.407	0.432	0.134	1.973	0.554	0.131	0.684	0.015	2.672
902	18.780	1.672	0.103	20.555	0.625	0.168	0.793	0.000	21.349
903	100.196	5.323	0.297	105.816	1.328	0.331	1.659	0.000	107.475
905	0.024	0.001	0.297	0.322	0.000	0.000	0.000	0.016	0.338
Total	122.698	7.428	0.831	130.957	2.507	0.630	3.137	0.030	134.124
Percent	91.5%	5.5%	0.6%	97.6%	1.9%	0.5%	2.3%	0.0%	100.0%

Note: Excludes EOR

1 4. Miscellaneous Revenues

2 Miscellaneous revenues totaled \$43 million in 2002. The source and functionalization of
3 the \$43 million of Miscellaneous Revenues is shown in Table 15 below. The largest source of
4 miscellaneous revenues is derived from the Service Establishment Charge at \$24 million. Since
5 storage costs are allocated based on SoCalGas' FRCA application, \$6 million of storage-related
6 miscellaneous revenues have been classified as transmission-related in conformance with the
7 FRCA filing.

8 Table 15 also shows the total classification of miscellaneous revenues. Customer-related
9 miscellaneous revenues totaled \$35 million or 81%, Distribution-related miscellaneous revenues
10 totaled \$1.4 million or 3%, Transmission-related totaled \$7 million or 15% and Non-Energy
11 Efficiency Customer Services-related totaled \$243,000 or 0.6%. Of the \$35 million in
12 customer-related miscellaneous revenues, 99 percent were credited to core customers' and the
13 remaining one percent to non-core customers' rates. The high-pressure, medium-pressure and
14 Customer Service and Information-related miscellaneous revenues were credited to customer
15 classes rates based on high-pressure and medium-pressure demand measures and the overall
16 Customer Services and Information cost allocation method.

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Table 15

Classification of Miscellaneous Revenues
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Line Description	PUC or SAP account	Recorded Year 2002	Functionalization
1 Service Establishment Charge	488.003 .503	23,606	Customer Related
2 Appliance Finance Commission	495.000	222	Customer Related
3 CIAC Amortization	495.051	(1,501)	Customer Related
4 Commercial Parts Program	488.005	1,731	Customer Related
5 Reconnection Charge	488.002	1,530	Customer Related
6 Pipeline Services	4330076	2,165	Customer Related
7 Residential Parts Program	488.006	915	Customer Related
8 Returned Check Charge	495.032	568	Customer Related
9 Connect Appliance Services	488.009	498	Customer Related
10 Line Item Billing	495	240	Customer Related
11 Other Customer Services Revenues	488	117	Customer Related
12 Subscription Services	4370017	548	Customer Related
13 Natural Gas vehicle Maintenance	488	370	Customer Related
14 Training Activity	495.058	121	Customer Related
15 Mapping Services	495.021	73	Distribution
16 Crude Oil Sales	495.021	4,403	Transmission
17 Sto Eng Emission & ReclaimCredits	495.021	1,529	Transmission
18 Aliso - Crimson, Termo, Road access	495.021	92	Transmission
19 Customer Solutions (Air Quality)	488.015	41	Customer Service & Info
20 Energy Resource Center	488	5	Customer Service & Info
21 Flower St. Gain on sales Amortization	495.052	2,826	A&G
22 Other Revenues	various	1,598	A&G
23 Rent Property Used in Operations	493	398	A&G
24 Reconcillation with FERC Form 2	Various	428	A&G
25 Shared Assets	various	528	A&G
26 Total Miscellaneous Revenues		43,051	

5. Non-Energy Efficiency (EE) Customer Service and Information Expenses

Non-Energy Efficiency Customer Service and Information Expenses are recorded in FERC Accounts 907 through 910. Energy Efficiency-related costs were excluded from the ECS because these costs are not included in Base Margin. The total direct Non-Energy Efficiency Customer Services and Information Expenses included in the ECS were \$16.5 million in 2002 as shown in Table 16 below. EOR-related CS&I costs were excluded from the ECS.

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Table 16

Allocation of Customer Service & Information Costs
(\$ 2002)

Rate Class	CS&I Cost
Residential	\$7,791,933
Core C&I	4,811,976
Gas-AC	72
Gas Engines	3,569
NGV	942,362
Non-Core C&I	1,450,555
Electric Gen.	885,705
Long Beach	156,670
SDG&E	131,602
South West Gas	104,446
Vernon	131,602
DGN	52,223
TOTAL	\$16,462,716

Residential customers were allocated \$7.8 million, core commercial customers \$4.8 million, NGV \$0.9 million and other core about \$4,000 of these Customer Services & Information expenses. Non Core C&I customers were allocated \$1.4 million, Electric Generation customers \$0.9 million and wholesale and international customers \$.8 million.

6. Administrative and General Expenses

Administrative and General (A&G) expenses are recorded in FERC Accounts 920 through 935. Recorded A&G expenses totaled \$368 million in 2002. Of that amount \$5.8 million of Public Purpose RD&D was excluded since it is not part of base margin. Also, 3.6 percent of total A&G-related to Storage costs was excluded from the ECS consistent with SoCalGas' FRCA application. In addition, \$39 million of Franchise Fee expenses were excluded because these costs are accounted for in the Franchise Fee and Uncollectibles factor in the volumetric commodity rate. Therefore, \$312 million of A&G costs were included in the ECS as shown in Table 17 below.

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Table 17
A&G Classification
(\$ Millions)

Line	FERC Item	Factor	Customer- Related	High Pressure	Medium Pressure	Trans. ¹	Non-EE CS&I	Total
1	920 Salaries	Labor	32.886	0.310	3.610	3.069	1.226	41.101
2	921 Office Supplies & Expenses	Multi	14.028	0.650	4.423	2.415	0.688	22.203
3	922 (Less) Admin Exp Transferred	Multi	(1.036)	(0.048)	(0.327)	(0.178)	(0.051)	(1.640)
4	923 Outside Services: Labor-related	Labor	9.393	0.088	1.031	0.877	0.350	11.739
5	923 Outside Services: Multifactor	Multi	66.429	3.079	20.944	11.436	3.256	105.143
6	924 Property Insurance	Plant	0.610	0.126	0.723	0.277	0.001	1.737
7	925 Injuries & Damages	Multi	13.825	0.641	4.359	2.380	0.678	21.883
8	926 Employee Pensions & Benefits	Labor	56.874	0.536	6.244	5.307	2.120	71.081
9	927 Franchise Fees	NA	-	-	-	-	-	-
10	928 Regulatory Commission Exp.	Multi	0.111	0.005	0.035	0.019	0.005	0.175
11	930 Miscellaneous General Exp.	Multi	3.844	0.178	1.212	0.662	0.188	6.084
12	931 Rents	Labor	22.515	0.212	2.472	2.101	0.839	28.139
13	935 Maintenance of General Plant	Labor	3.389	0.032	0.372	0.316	0.126	4.235
14	14 Total		222.867	5.808	45.098	28.680	9.426	311.881
15	15 Percent of Total		71.5%	1.9%	14.5%	9.2%	3.0%	100.0%
16								
17	17 408 Payroll taxes	Labor	18.176	0.171	1.996	1.696	0.678	22.717

To allocate A&G costs, O&M expenses excluding A&G, Net Plant excluding General Plant, and Labor expenses were used to classify A&G costs as Customer-, Demand- and Non-EE Customer Services and Information-related expenses. A&G expenses were classified as Customer-, Demand-, and Non-EE Customer Services and Information-related expenses based on three factors: recorded O&M expenses; Net Plant excluding General Plant; and Labor expenses incurred in 2002. The three factors that were used to classify the various accounts are shown in Table 18.

Those expenses that could not be placed into a single category were allocated using a multi factor allocation method. The multi factor was derived by taking the simple average of O&M, Net Plant capital-related costs and Labor percentages. This method captures a fair allocation of certain A&G costs by functional category because O&M, Net Plant and Labor expenses are good indicators of cost causality in allocating A&G expenses.

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Table 18
Basis for A&G Classification
(\$ Millions 2002)

Function	O&M Expense (a)	Net Plant Excl Gen Plnt (b)	Labor Dollars (c)
Customer-Related	293.810	769.594	180.437
Distribution			
High Pressure	3.160	157.826	1.699
Medium Pressure	36.837	909.013	19.810
Subtotal	39.997	1,066.839	21.509
Transmission	36.325	348.874	16.838
Non-DSM Cust Svc & Info	28.791	1.092	6.726
Total	398.923	2,186.399	225.510

The cost percentages used in the multi factor allocation method are shown in Table 19 below.

Table 19
A&G Classification Factors
(Percent)

Ln	Function	O&M Expense (a)	Net Plant (b)	Labor Dollars (c)	Multi- Factor (d)
1	Customer-Related	74.4%	35.2%	80.0%	63.2%
2	Distribution				
3	High Pressure	0.8%	7.2%	0.8%	2.9%
4	Medium Pressure	9.3%	41.6%	8.8%	19.9%
5	Subtotal	10.1%	48.8%	9.5%	22.8%
6	Transmission	9.2%	16.0%	7.5%	10.9%
12	Non-EE Cust Svc & Info	6.3%	0.0%	3.0%	3.1%
13	Total	100.0%	100.0%	100.0%	100.0%

The following FERC account expenses were classified using the multi factor: Account 921, Office Supplies and Expenses; Account 922 Administrative Expenses transferred; Account 925 Injuries and Damages; Account 928, Regulatory Commission Expenses; and Account 930,

Miscellaneous General Expenses. The Labor factor was used to allocate: Account 920, Salaries; Account 926, Employee Pension and Benefits; Account 931, Rents; Account 935, Maintenance of General Plant; and, Account 408, Payroll Taxes. The Plant factor was used to classify Account 924, Property Insurance expenses.

FERC Account 923, Outside Services, was further broken down into Labor and multi factor subcomponents. This breakdown is shown in Table 20 below. The \$31 million adjustment to shared services reflects reassignments and overheads. Outside Services provided to the Human Resources Department, Shared Services, and Pension and Benefits-related outside services were classified by using the Labor factor. These costs were classified using Labor because most of the shared services are labor-related expenses. General Counsel, External Affairs, Information Technologies, Office of the Chairman, Accounting and Finance, Depreciation, and various reassignments were classified using the multi factor, since these costs are across all lines of business.

Table 20

FERC Account 923 Classification Factors

Ln	Item	\$MM	Adj	\$MM	Code
1	General Counsel	14.832		14.832	Multi
2	External Affairs	3.099		3.099	Multi
3	Communications	1.243		1.243	Multi
4	Administrative Services	1.099		1.099	Labor
5	Bldg. & Real Estate	3.705		3.705	Labor
6	Environmental & Safety	1.006		1.006	Multi
7	Procurement & Logistics	0.130		0.130	Multi
8	Office Services	0.337		0.337	Labor
9	Information Technology	7.515		7.515	Multi
10	Office Of Chairman	1.116		1.116	Multi
11	Accounting & Finance	14.925		14.925	Multi
12	Human Resources	6.599	-	6.599	Labor
13	Misc. Expenses	0.014		0.014	Multi
14	Depreciation	18.016		18.016	Multi
15	Shared Services, SDG&E & Recon.	12.134	31.113	43.248	Multi
16		85.769	31.113	116.882	116.882

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7. Payroll Taxes.

FERC Account 408 shows recorded payroll taxes of \$23.6 million in 2002. Of this total \$0.8 or 3.6 percent million is attributable to Storage and was excluded from the ECS. The remaining \$22.7 million was classified as follows: \$18.2 customer-related; \$0.171 million High-pressure distribution; \$2 million Medium pressure distribution; and, \$0.678 million Non-EE Customer Services and Information-related expenses. Payroll taxes were then further classified by the same percentage as the level of labor expenses in each FERC Account.

The classification of labor expenses is shown in Table 21 below. Of the \$225.5 million in 2002 labor expenses, \$180.4 million were classified as customer-related, \$1.6 million as HP Distribution, \$19.8 million as MP Distribution and \$16.8 million as Transmission-related.

Table 21

Labor Expenses Classification
(\$ Millions)

Functions	\$MM	Percent
Customer-Related	180.437	80.0%
High Pressure Dist	1.699	0.8%
Medium Pressure Dist	19.810	8.8%
Transmission	16.838	7.5%
	225.510	100.0%
Customer-Related		
C-R Distribution	111.951	62.0%
Customer Accts	68.486	38.0%
Subtotal	180.437	100.0%

8. Franchise and Uncollectible Expenses

Recorded Franchise and Uncollectible Expenses (F&U) totaled \$39 million in 2002; however, a portion of these costs relate to non-base margin items, e.g., gas costs. The portion of these costs related to distribution were accounted for in the ECS by using the adopted Franchise and Uncollectible factors of 1.4828 percent and 0.4776 percent, respectively, per D.97-07054, SoCalGas' currently effective PBR decision. A gross up F&U factor of 1.0199 was used for retail and a Franchise Fee gross up factor of 1.0151 for wholesale customer expenses to account for these costs. These factors were applied across the total un-reconciled embedded costs plus a

component for franchise fees applicable to service establishment charges recorded in miscellaneous revenues.

V. Functionalization, Classification and Allocation of Net Plant

1. Functionalization, Classification and Allocation of Distribution Plant

Distribution plant is recorded in FERC Accounts 374 through 387 and totaled \$1,837 million in 2002 as shown in Table 22 below. Of this total, \$763 million was classified as customer-related, \$156 million as high pressure-related, \$908 million as medium pressure-related, \$8 million as Exclusive Use main facilities.

Table 22

Classification of Distribution Plant
Net Book Value
(\$ Millions)

Ln	Acct	Sub	Item	Customer- Related	High Pressure	Medium Pressure	Exclusive Use And Other	Total
1	374	374.100	Land	22.237	0.439	5.123	-	27.799
2	374	374.200	Land Rights	-	0.192	2.242	-	2.434
3	375	375.000	Structures & Impr	73.135	1.445	16.848	-	91.428
4	376	376.000	Mains-Incl. Catho	-	154.267	867.366	0.209	1,021.842
5	376	376.050	Mains - Deep Well	1.466	0.262	2.030	-	3.758
6	378	378.100	Meas & Reg Stn Equip	-	1.385	16.148	-	17.533
7	380	380.000	Services	358.783	-	-	-	358.783
8	381	381.000	Meters	191.397	-	-	-	191.397
9	382	382.000	Customer Installations	42.905	-	-	-	42.905
10	382	382.600	GEMS	14.169	-	-	-	14.169
11	383	383.000	House Regulators	58.997	-	-	-	58.997
12	387	387.100	Other Equipment	-	(0.012)	(0.138)	-	(0.149)
13	387	387.200	Fueling Stns-NGV	-	-	-	6.446	6.446
14	387	387.600	Street Light. Equip	(0.068)	-	-	-	(0.068)
15	Total			763.022	157.979	909.619	6.655	1,837.274
16	Percent of total			41.5%	8.6%	49.5%	0.4%	100.0%

1 FERC Accounts 374.100, Land, and 375, Structures & Improvements, were classified as
2 73 percent customer-related because these facilities support the field workforce and therefore
3 these costs were classified the same as distribution O&M costs as shown in Table 10, above.
4 Account 374.200 includes rights-of-way expenses related to distribution mains and this plant was
5 classified based on the total footage of high-pressure, 7.9 percent, and medium pressure, 92.1
6 percent, main in service. This footage breakdown is shown on lines 24 and 25 of Table 23
7 below.

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1 Account 376 totals \$1,022 million of mains. FERC Sub-Account 376.050 includes \$4
2 million for cathodic protection of steel distribution mains and service lines. This cathodic
3 protection plant was classified as customer-related and demand-related based on the percentage
4 of steel services and steel distribution mains in service. Account 378 shows \$17.5 million for
5 regulator station equipment. These costs were classified between high pressure and medium
6 pressure-related plant based on the percentage of high pressure, 7.9 percent, and medium
7 pressure, 92.1 percent, main footage in service as shown in Table 23. From Account 376, \$1.5
8 million was designated as Exclusive Use main plant and was subtracted from the total and
9 assigned to the customers that are exclusively served by these mains. The remaining distribution
10 main plant was classified based on high pressure, 15.1 percent, and medium pressure, 84.9
11 percent, net plant in service as shown on line 25 of Table 24 below.

12 Account 380, Services, shows \$359 million; Account 381, Meters, shows \$191 million;
13 Account 382, Customer Installations, shows \$43 million; Account 382.6, GEMS (Gas Energy
14 Measurement System), shows \$14 million; Account 383, House Regulators, shows \$59 million
15 of NBV for 2002. These costs were classified as customer-related, since they are used to provide
16 service to individual customer locations. Services were allocated to customer classes based on
17 the percentage of services' NBV in each customer class. Overall, the residential customer class
18 was allocated \$331 million of NBV of service lines in service. This allocation was based on
19 records of the Service History file and the Customer Information system which showed that the
20 more than 5 million residential customers were using about 87 percent of the 228 million feet of
21 service line in service. Meters and Customer Installation costs were allocated based on the
22 percentage of meter NBV in each customer class. GEMS costs were assigned to each customer
23 or customer class based on the company-owned GEMS meters used to serve that customer or
24 customer class using actual plant accounting records. Regulators were allocated to customer
25 classes based on the percentage of regulators' NBV in each customer class. The NBV of gauges,
26 above standard pressure meters, were separated from Account 381 and allocated to customer
27 classes based on the percentage of NBV of above standard pressure meters in each customer
28 class. Most gas meters operate at standard pressure or 8 inches of water column. Gauges are
mechanical or electronic devices connected to meters that operate above standard pressure. In
the ECS, gauge-related costs, based on a \$7.4 million net book value, were allocated to customer
classes based on the number of meters above standard pressure.

1 Exclusive use main facilities are mains that were capitalized as distribution mains but are
 2 used as large service lines. Plant Accounting identified \$209,000 of NBV as exclusive use
 3 facilities. These costs were allocated to those classes of customers receiving service using these
 4 facilities.

5 Table 24

6 Distribution Main Footage and Net Book Value by Service Pressure and Type
 7 (1/1 2002)

Ln.	Type	Size	Medium Pressure Footage (c)	High Pressure Footage (d)	Total Footage e = (c+d)	Percent High Pressure e f=(d/e)	Total NBV (\$) (g)	High Pressure NBV (\$) h=(g*f)
12	1	Steel 1/2"	1,929	0	1,929	0%	(\$1,373)	\$0
13	2	Steel 3/4"	60,618	8,704	69,322	13%	\$215,862	\$27,103
14	3	Steel 1.0"	3,205,907	108,221	3,314,128	3%	\$1,137,805	\$37,154
15	4	Steel 1.25"	1,257,379	3,065	1,260,444	0.2%	\$497,071	\$1,209
16	5	Steel 2"	72,043,308	1,536,349	73,579,657	2%	\$31,020,701	\$647,715
17	6	Steel 3"	18,378,647	1,026,735	19,405,382	5%	\$19,217,944	\$1,016,818
18	7	Steel 4"	16,153,129	2,610,863	18,763,992	14%	\$36,593,916	\$5,091,758
19	8	Steel 6"	9,602,470	4,349,305	13,951,775	31%	\$82,577,385	\$25,742,548
20	9	Steel 8"	3,112,249	3,636,696	6,748,945	54%	\$57,372,363	\$30,915,329
21	10	Steel 10"	1,029,200	1,858,559	2,887,759	64%	\$22,398,061	\$14,415,371
22	11	Steel 12"	519,342	2,126,660	2,646,002	80%	\$34,550,785	\$27,769,356
23	12	Steel 16"	344,260	1,433,524	1,777,784	81%	\$28,230,168	\$22,763,521
24	13	Steel 20"	64,794	321,789	386,583	83%	\$20,190,070	\$16,806,074
25	14	Steel 24"	17,815	38,986	56,801	69%	\$9,100,978	\$6,246,558
26	15	Steel 26"	21,323	25,752	47,075	55%	\$1,096,608	\$599,891
27	16	Steel 30"	9,562	14,997	24,559	61%	\$116,925	\$71,400
28	17	Plastic 1/2"	25,866	0	25,866	0%	\$124,295	\$0
29	18	Plastic 1.0"	3,911,378	0	3,911,378	0%	\$10,643,180	\$0
30	19	Plastic 2"	71,253,539	0	71,253,539	0%	\$451,887,512	\$0
31	20	Plastic 3"	9,610,781	0	9,610,781	0%	\$69,458,141	\$0
32	21	Plastic 4"	10,049,245	0	10,049,245	0%	\$100,001,182	\$0
33	22	Plastic 6"	853,269	0	853,269	0%	\$20,714,079	\$0
34	23	Plastic 8"	241,063	0	241,063	0%	\$9,837,845	\$0
35	24	TOTAL	221,767,073	19,100,205	240,867,278		\$1,006,981,501	\$152,151,804
36	25						H-P NBV	15.1%

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a. Allocation of Demand-Related Distribution.

SoCalGas' ECS used the BCAP period forecasted Cold-Year Coincident Peak Month throughput to allocate high-pressure distribution load costs and the 1-in-35 Year Peak Day throughput to allocate medium-pressure distribution load costs. These cost allocation methods are consistent with past Commission decisions.

2. Functionalization, Classification and Allocation of Transmission Expenses

Transmission plant NBV totaled \$348 million at year end 2002. The major portion of Transmission plant was mains at \$246 million, followed by compressor station equipment at \$66 million, Measurement Station and Regulator Station Equipment at \$15 million, Land and Rights-of-Way at \$12 million, Structures and Improvements at \$8 million and Other Transmission Equipment at \$2 million. These totals are shown in Table 25. The \$83 million Transmission capital-related costs of return, depreciation and taxes, were classified as demand-related. The Transmission capital-related costs are shown in Table 2 above.

Table 25
Functionalization of Transmission Plant

Ln	Acct	Sub	Item	\$ Millions
1	365	365.100	Land	1.910
2	365	365.200	Rights Of Way	10.254
3	366	366.000	Struc. & Imprmnt	7.872
4	367	367.000	Mains	246.543
5	368	368.000	Compres Stn Equip	65.527
6	369	369.100	Meas & Reg Stn Equip	14.550
7	371	371.000	Other Equipment	1.639
8	Total			348.295

a. Demand-Related Transmission.

SoCalGas' ECS used the BCAP period forecasted Cold-Year Throughput to allocate Transmission costs. This cost allocation method is consistent with past Commission decisions.

3. Natural Gas Vehicle (NGV) Fueling Stations and CS&I Costs

NGV fueling stations support Company operations for mandated NGV activities and for fueling non-company-owned NGVs. Account 387.200, Fueling Stations-NGV, included \$6.4 million in NBV of SoCalGas-owned NGV station compressor net book value. The associated capital-related costs of these stations were \$1.9 million in 2002. These fueling stations were built to meet Federal regulations on alternative fuel vehicle requirements. These stations provide fuel for company-owned NGVs that support all functions. In addition to all capital-related costs, O&M costs and A&G associated with company-owned compressor stations were allocated to all customer classes using fleet clearing account factors, i.e., the assignment of fleet expenses related to vehicles and garages. The NGV customer class' allocation of O&M, A&G, and capital-related costs is \$5.1 million. This includes \$800,000 of capital-related costs allocated as described above, and \$2.3 million of Customer Service and Information costs.

a. NGV Compressed Gas Adder.

Company-owned fueling stations provide compressed natural gas to company vehicles and to the public. The portion of the costs of company-owned NGV stations that provide public access totaled \$1.26 million in 2002 as shown in Table 26. This total includes \$0.956 million of capital-related costs; \$0.163 million of costs that cover O&M, A&G, and a share of the reconciliation amount; and \$0.142 million for electricity to run the compressors.

Table 26
NGV Fueling Stations Costs
(\$ Millions)

Return	0.178
Depreciation	0.622
Taxes	0.157
<u>Capital Costs</u>	<u>0.956</u>
O&M	0.163
Electricity	0.142
<u>Total Public Costs</u>	<u>1.262</u>

These costs were used by SoCalGas witness Steve Lango to develop the compression adder for compressed NGV service. This adder ensures that customers using company-owned NGV fueling stations pay for the additional costs to provide public access compressed gas.

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Table 28

General Plant Capital-Related Costs Net of FRCA
Exclusions
(\$ Millions)

General Plant NBV	242.169
Total NBV	<u>2,428.568</u>
Percent of Total	10.0%
Capital-Related GP Costs minus Storage Portion	
Return	18.484
Depreciation	23.738
Taxes	<u>16.235</u>
GP Capital-related costs	<u>58.457</u>

Cost Allocation details are shown in Table 29 below.

Table 29

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Ln	Function	\$MM	Allocator Code	Residential	G-10	G-AC	G-GE	NGV	Subtotal Core
	Customer-Related O&M								
	O&M								
1	Dist Customer Services	220.736	P-Hrs&Nums	190.384	29.705	0.000	0.043	0.008	220.140
2	Dist Meter & House Regs	57.347	Mtrs*UC	48.585	7.919	0.003	0.126	0.037	56.669
3	Dist Service Lines	72.760	SvcFtg	63.054	4.711	0.001	0.261	0.008	68.036
4	Customer Accounts	277.842	CAccts	254.158	15.387	0.068	0.511	0.527	270.651
5	Subtotal	628.684		556.182	57.722	0.072	0.941	0.579	615.496
6	Capital-Related Costs								
7	Dist Land, Structures, & Imprvmnts	29.417	DO-O&M	25.323	3.550	0.000	0.036	0.004	28.914
8	Services	111.194	SvcNBV	102.475	7.602	0.002	0.773	0.031	110.883
9	Meters	56.800	MtrNBV	45.155	10.404	0.005	0.203	0.062	55.830
10	Customer Installations	13.243	MtrNBV	10.528	2.426	0.001	0.047	0.014	13.017
11	GEMS NBV	4.373	GEMS	-	-	-	-	-	-
12	Regulators	18.210	RegNBV	8.662	7.040	0.002	0.113	0.074	15.890
13	Gauges	2.277	AbvStd	0.431	1.712	0.001	0.054	0.007	2.205
14	Exclusive Use Mains	0.244	EU	-	-	-	-	-	-
15	Subtotal	235.757		192.574	32.733	0.012	1.227	0.193	226.739
16	Customer-Related Misc Revenues	(34.780)	MiscRev	(33.993)	(0.785)	(0.000)	(0.002)	(0.000)	(34.780)
17	Subtotal Customer-Related	829.661		714.763	89.670	0.084	2.166	0.772	807.455
18	Distribution								
19	High-Pressure	48.519	CYPM-D	30.699	7.822	0.009	0.040	0.326	38.896
20	Medium-Pressure	316.370	CYPD	252.674	51.397	0.028	0.142	0.351	304.593
21	Subtotal	364.889		283.373	59.219	0.037	0.182	0.677	343.489
22	Transmission	155.220	CYTP	51.997	17.732	0.033	0.481	1.357	71.600
23	Storage Excluded from Base Margin								
24	Core Reservation								
25	Inventory	15.862	Core-INV	13.806	2.031	-	-	0.026	15.862
26	Injection	14.064	Core-INJ	12.240	1.801	-	-	0.023	14.064
27	Withdrawal	11.918	Core-WDL	9.886	2.011	0.001	0.006	0.014	11.918
28	Subtotal	41.843		35.932	5.842	0.001	0.006	0.062	41.843
29	Load Balancing Excluded from Base Margin								
30	Inventory	1.201	LB-INV	-	-	-	-	-	-
31	Injection	10.752	LB-INJ	-	-	-	-	-	-
32	Withdrawal	1.540	LB-WDL	-	-	-	-	-	-
33	Subtotal	13.493		-	-	-	-	-	-
34	Unbundled Storage Ex. From Base Margin	(55.336)	UBStor	-	-	-	-	-	-
35	Subtotal Excludes Storage Cost	-		35.932	5.842	0.001	0.006	0.062	41.843
36	Non-DSM Cust Svc & Info	39.666	CS&I	18.774	11.594	0.000	0.009	2.271	32.647
37	Subtotal	1,389.435		1,068.908	178.215	0.154	2.837	5.077	1,255.191

	G-30	G-50 Elect Gen Cogen	Subtotal Retail Noncore	Long Beach	SDG&E	Southwest Gas	Vernon	Subtotal Wholesale	DGN	Subtotal Internat'l	Subtotal Noncore	Tota System
	0.588	0.008	0.596	-	-	-	-	-	-	-	0.596	220.736
	0.434	0.213	0.647	0.001	0.020	0.008	-	0.028	0.002	0.002	0.678	57.347
	4.711	0.013	4.724	-	-	-	-	-	-	-	4.724	72.760
	5.193	1.305	6.498	0.026	0.232	0.403	0.018	0.678	0.015	0.015	7.191	277.842
	10.926	1.539	12.465	0.027	0.251	0.411	0.018	0.707	0.017	0.017	13.188	628.684
	0.481	0.020	0.500	0.000	0.002	0.001	-	0.002	0.000	0.000	0.503	29.417
	0.244	0.068	0.311	-	-	-	-	-	-	-	0.311	111.194
	0.664	0.281	0.944	0.001	0.008	0.012	-	0.021	0.004	0.004	0.970	56.800
	0.155	0.065	0.220	0.000	0.002	0.003	-	0.005	0.001	0.001	0.226	13.243
	0.179	3.769	3.948	0.108	0.204	0.092	0.021	0.425	-	-	4.373	4.373
	1.372	0.947	2.318	0.001	0.000	0.000	-	0.001	-	-	2.320	18.210
	0.057	0.014	0.071	0.000	0.000	0.001	-	0.001	0.000	0.000	0.072	2.277
	-	0.053	0.053	-	-	-	0.190	0.190	-	-	0.244	0.244
	3.150	5.216	8.366	0.110	0.217	0.109	0.211	0.647	0.005	0.005	9.018	235.757
	(0.000)	(0.000)	(0.000)	-	-	-	-	-	-	-	(0.000)	(34.780)
	14.076	6.754	20.830	0.137	0.468	0.520	0.229	1.353	0.022	0.022	22.206	829.661
	5.584	4.040	9.624	-	-	-	-	-	-	-	9.624	48.519
	10.439	1.338	11.777	-	-	-	-	-	-	-	11.777	316.370
	16.022	5.378	21.400	-	-	-	-	-	-	-	21.400	364.889
	21.833	35.349	57.182	1.846	20.455	1.629	1.693	25.623	0.814	0.814	83.619	155.220
	-	-	-	-	-	-	-	-	-	-	-	15.862
	-	-	-	-	-	-	-	-	-	-	-	14.064
	-	-	-	-	-	-	-	-	-	-	-	11.918
	-	-	-	-	-	-	-	-	-	-	-	41.843
	0.316	0.515	0.830	0.026	0.287	0.022	0.025	0.359	0.012	0.012	1.201	1.201
	2.825	4.609	7.434	0.230	2.566	0.195	0.221	3.212	0.106	0.106	10.752	10.752
	0.405	0.660	1.065	0.033	0.368	0.028	0.032	0.460	0.015	0.015	1.540	1.540
	3.545	5.784	9.328	0.288	3.221	0.245	0.277	4.031	0.133	0.133	13.493	13.493
	-	-	-	-	-	-	-	-	-	-	(55.336)	-
	3.545	5.784	9.328	0.288	3.221	0.245	0.277	4.031	0.133	0.133	(41.843)	55.336
	3.495	2.134	5.629	0.377	0.317	0.252	0.317	1.263	0.126	0.126	7.018	39.666
	55.427	49.615	105.042	2.360	21.240	2.401	2.239	28.240	0.962	0.962	134.244	1,389.435
	0.005	0.005	0.010	(0.011)	(0.101)	(0.011)	(0.011)	(0.135)	0.000	0.000	(0.124)	(0.001)
	55.432	49.620	105.052	2.349	21.138	2.389	2.228	28.105	0.962	0.962	134.119	1,389.434
	-	-	-	-	-	-	-	-	-	-	-	-
	55.432	49.620	105.052	2.349	21.138	2.389	2.228	28.105	0.962	0.962	134.119	1,389.434

This concludes my testimony.

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QUALIFICATIONS

My name is Herbert S. Emmrich. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. I am employed by Southern California Gas Company as Principal Regulatory Economic Advisor in the State Regulatory Affairs Department. I have been in this position since August 2002. I have previously testified before this Commission.

My academic and professional qualifications are as follows: I earned an undergraduate degree in Economics and Behavioral Sciences from California State University at Dominguez Hills in 1970 and a Master of Arts Degree in Economics from California State University at Long Beach in 1974. In addition, during the past 18 years, I held analyst and management positions in the Regulatory Affairs, Planning, Customer Services, Marketing, Gas Supply and Commercial and Industrial Services Departments of SoCalGas. My employment outside of SoCalGas has been in the areas of economics, environmental assessment, business planning and energy sector development. I held the positions of: Economist, Regional Economist and Environmental Assessment Manager at the U.S. Bureau of Land Management's Pacific Outer Continental Shelf Office, in Los Angeles, from 1975 to 1979; Economic Policy Supervisor and Issues and Policy Manager of Getty Oil Company from 1979 to 1984; and, Senior Energy Advisor of the U.S. Agency for International Development's Caucasus Office in Tbilisi, Republic of Georgia, from 1998 to 2002.