

Application No.: A.03-09-

Exhibit No.: _____

Date: September 3, 2003

Witness: Brenda H. Chen

**PREPARED DIRECT TESTIMONY OF
BRENDA H. CHEN
SOUTHERN CALIFORNIA GAS COMPANY**

September 3, 2003

2005 BIENNIAL COST ALLOCATION PROCEEDING

1 Table 1: Forecast of Refinery G-30 and EG Gas Demand - Average Year (Mdth)

	<u>2005</u>	<u>2006</u>	<u>Average</u>	
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3				
4	Refinery G-30 Gas Demand	47,140	47,588	47,364
5	<u>Refinery-Related EG Demand</u>	<u>12,188</u>	<u>12,304</u>	<u>12,246</u>
6	Total Refinery Gas Demand	59,328	59,892	59,610

7 The refinery segment demand forecast was prepared using an econometric multiple log-
 8 linear regression model. In the model, total refinery gas demand is a function of the forecast
 9 prices of natural gas and butane (an alternate fuel to natural gas). SoCalGas witness Ms. Loan X.
 10 Nguyen sponsors the forecasts of natural gas and butane prices.

11 After generating the forecast of total refinery gas demand, estimated incremental load
 12 reductions due to the impact of California Air Resources Board (CARB) III gasoline regulations
 13 were subtracted from the econometric forecasts. The CARB has adopted a new set of
 14 specifications to be effective January 2004 called CARB III Reformulated Gasoline (RFG). The
 15 CARB III RFG regulations call for the replacement of methyl tertiary butyl ether (MTBE) with
 16 ethanol and for a reduction in sulfur and benzene levels. In order to comply with the CARB III
 17 RFG regulations, refiners will be forced to modify their facilities and operations to produce
 18 gasoline compliant with CARB regulations, or reduce refinery operations and import product
 19 from out of the area. The forecast assumes the refineries implement modifications, rather than
 20 import product, that result in the production of excess pentanes that are suitable to displace some
 21 existing natural gas demand for refinery and refinery-related cogeneration loads and for
 22 hydrogen plant feedstock. In a December 2002 report, Purvin & Gertz Inc., a consultant
 23 specializing in refinery operations, estimated that the amount of pentane substitution for natural
 24 gas in refineries for the years 2005-2006 could go as high as 80 Mdth/Day if the burner tip
 25

1 natural gas prices exceed \$4.12/Dth during the summer period. The summer period as defined
2 by the CARB gasoline regulations currently includes the seven months April through October,
3 but will increase to the eight months March through October beginning in 2005. Appendix 1 to
4 my testimony is the Executive Summary of the Purvin & Gertz report.

5 Finally, the total forecasted refinery gas volumes were split into rate-class G-30 and EG
6 volumes based on percentages derived from billing records of refinery customers from June 2000
7 through March 2003. These percentages reasonably predict the allocation of refinery gas
8 volumes for rate class G-30 and EG customers for the BCAP forecast period.

9 SoCalGas forecasts that total refinery segment usage will be approximately 59,328 Mdth
10 and 59,892 Mdth for calendar years 2005 and 2006, respectively. For 2005, this is a decrease of
11 24,964 Mdth from the recorded 12 months ending March 2003 throughput of 84,292 Mdth. Of
12 the 24,964 Mdth reduction, approximately 19,600 Mdth is due to pentane switching and the
13 remaining 5,364 Mdth is primarily due to refineries using butane instead of natural gas as a result
14 of high natural gas prices. The last Table in Appendix 1 shows several threshold natural gas
15 price levels that will trigger switching to pentanes and the associated volume of natural gas
16 displaced in refineries. As indicated in the table, in year 2005, if the burner tip natural gas price
17 exceeds \$4.12/Dth (Third Threshold Price), then 80 Mdth/Day of natural gas will be displaced by
18 pentanes. And if natural gas prices are between \$3.92/Dth (Second Threshold Price) and
19 \$4.12/Dth, then 64.6 Mdth/Day of natural gas will be displaced. Since the entire summer
20 months' natural gas prices in the year 2005 and 2006 are forecast to exceed the \$4.12/Dth
21 threshold, the 2005 and 2006 pentane switching volumes are forecast to be 19,600 Mdth and
22 19,478 Mdth, respectively.

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1 **2. Marginal Demand Measures**

2 The marginal demand measures for the refinery segment are developed with the proposed
3 heating degree-days for average-temperature-year and cold-temperature-year conditions
4 sponsored by SoCalGas witness Mr. Christopher H. Roberts. The number of heating degree days
5 in the average-temperature-year and cold-temperature-year forecasts is 1,386 and 1,708,
6 respectively.

7 The peak month demand is the December demand under cold year temperature
8 conditions for customers served from high-pressure distribution lines. The percentages of
9 refinery rate-classes G-30 and EG volumes served from high-pressure distribution lines are 38%
10 and 23%, respectively. The peak day demand is the daily December demand under a design 38
11 degree Fahrenheit peak day condition for customers served from medium pressure distribution
12 lines. The refinery segment has no customers served from medium pressure distribution lines.
13 Table 2 below shows the forecast Marginal Demand Measures for the refinery market segment.

14
15 *Table 2. Forecast of Marginal Demand Measures*

	2005	2006
Refinery G-30		
Number of Customers	19	19
Cold Year Demand	47,547 Mdth	47,995 Mdth
Peak Month Demand	2,094 Mdth	2,103 Mdth
Refinery EG		
Number of Customers	9	9
Cold Year Demand	12,188 Mdth	12,304 Mdth
Peak Month Demand	316 Mdth	317 Mdth

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24 This concludes my prepared testimony.

C. QUALIFICATIONS

My name is Brenda H. Chen and I am employed by SoCalGas. My business address is 555 West Fifth Street, Los Angeles, California, 90013 – 1011.

My present position is Senior Market Advisor in the Major Markets Customer Services Department. My responsibilities include managing the development and implementation of customer services policies and strategies related to the energy services provided to noncore customers. This includes gas service to refinery, cogeneration, and EG customers.

I have a Bachelor's degree in Economics from National Taiwan University, Taiwan, and a Masters of Science in Statistics from UCLA. During the 18 years of employment at SoCalGas, I have held positions of increasing responsibility in the Regulatory Affairs and Customer Services Departments.

I have previously testified before this Commission.

APPENDIX 1

Appendix 1

Purvin & Gertz Inc. Report

IMPACT OF NEW CALIFORNIA GASOLINE SPECIFICATIONS
ON NATURAL GAS DEMAND BY LOS ANGELES REFINERS

Prepared for Southern California Gas Company, December 2002

II. EXECUTIVE SUMMARY

Changes in the specifications for gasoline sold in California have been ordered by Governor Davis, which will become effective by December 31, 2003. The new specifications were originally set to take effect one year prior, but were delayed owing to concerns that gasoline shortages would occur, resulting in high prices. Several refiners in California have announced their intentions to produce gasoline meeting the new specifications ahead of the December 31, 2003 deadline. It is estimated that 65% of the gasoline produced by Los Angeles refiners may meet the new specifications by the summer of 2003.

The action is a result of the governor's determination that the gasoline "oxygenate" additive, MTBE, represents an environmental risk to California. MTBE has become a public health concern because it contaminates groundwater (along with other gasoline components) when leaks occur in underground service station tanks. The new gasoline formulation is referred to as CARB Phase III Reformulated Gasoline (RFG). The new specifications require the removal of the additive MTBE along with reductions in both sulfur and benzene. The use of an oxygenate additive in gasoline sold in Southern California is mandated by the federal Environmental Protection Agency (EPA). At this time the only approved alternate oxygenate currently available for gasoline blending is ethanol.

The changes in the gasoline formulation are significant and will force the refiners in the Los Angeles area to modify their facilities and the manner they are operated. The blending of ethanol causes the vapor pressure of the gasoline to be higher than if it were blended with MTBE. As a result, some portion of the high vapor pressure components in the base gasoline, including butanes and pentanes, must be rejected.

The rejection of pentanes is expected to occur only during the summer season when the vapor pressure of gasoline is controlled under current and future regulations. The summer period includes seven months (April 1 through October 31), but will increase to eight months (March 1 through October 31) beginning in the year 2005. Refiners must actually begin producing low-RVP gasoline ahead of the first day of the vapor control period in order to insure that the gasoline inventory throughout the distribution system is turned over before the deadline. Therefore, the summer production season will effectively become about 275 days.

Pentanes, a mixture of normal pentane and isopentane pentane, represent a potential substitute for natural gas in the refineries as feedstock for hydrogen production plants, fuel for gas turbine power plants and to a limited extent as supplemental fuel in boilers and process fired heaters. The incremental propane, butanes, and pentanes produced as a result of the change in gasoline specifications are estimated to total 107 MDTh/Day, 92 of which is pentanes.

The changes in the gasoline specifications will also result in an increased demand for hydrogen primarily due to the reduction in sulfur and aromatics. Refinery still gas, natural gas, propane and butane are the most common feedstocks for production of hydrogen. Pentanes can also be used as hydrogen plant feedstock and it is expected that the capacity of hydrogen plants in Los Angeles refineries to charge pentanes will increase in the future. The hydrogen plants in the Los Angeles area are anticipated to be able to substitute up to 76 MDTh/day of pentanes for natural gas.

Refineries consume a significant amount of fuel in the processing of crude oil, which includes firing gas in process heaters, boiler and cogeneration plants. Most of which is produced as a byproduct, but some supplemental natural gas is purchased. It is estimated that the refiners will have the capability to burn 25 MDTh/day of pentanes in fired heaters, boilers and cogeneration plants.

The value for pentanes as fuel in refineries is based on its BTU content at a price equivalent to the price of purchased natural gas in \$/MM BTU's. The value for pentane as hydrogen plant feedstock is based the volume of hydrogen produced per BTU at a price that is equivalent to the natural gas price. The efficiency of generating hydrogen from pentanes is less than natural gas. It requires about 7% more BTU's to produce a volume of hydrogen from pentanes compared to natural gas. Therefore, the value for pentanes as hydrogen plant feedstock, in terms of \$/MM BTU, is less than its value as straight burner fuel.

Substituting pentanes for natural gas requires that the equipment be technically capable of using it, including consideration of air emissions, as well as being dependent on the economics. If the price of natural gas becomes high enough, the value of the substitution materials as fuel and hydrogen plant feedstock can exceed their values in alternative markets thereby providing the incentive for substitution. Several viable alternate markets exist outside the refineries for the excess pentanes include storage for wintertime gasoline blending, petrochemical feedstock, and blending into conventional gasoline outside California. The use that commands the highest value back to the refinery will be a major factor in determining the disposition of the pentanes. However, price is not the only factor as each option has physical limitations associated with it.

The volume of incremental pentanes rejected during the summer season is expected to exceed the capacity of the refinery infrastructure to export it, which is estimated to be 7-13 MDTh/day between 2003 and 2007. As a result there will always be some pentane substitution in the refineries that occurs regardless of the economics. A summary of the pentane transfer constraints and the unavoidable natural gas substitution that results is shown in the table below:

TRANSFER LIMITING PENTANE SUBSTITUTION, MDTh/day				
	2003	2004	2005	2006
<u>Infrastructure Limitations</u>				
Rail Loading Capacity	46.2	46.2	46.2	46.2
Marine Shipment Capacity	-	37.0	37.0	37.0
Total Transfer Capacity	46.2	83.2	83.2	83.2
<u>Excess Pentanes Rejected</u>				
Total Transfer Capacity Limit	46.2	83.2	83.2	83.2
Transfer Limiting Pentane Substitution	12.1	8.3	9.8	11.3

The rail loading facilities for exporting of pentanes from the refineries is estimated to be 10,000 barrels per day or 46.2 MDTh/day. The infrastructure for marine loading of pentanes is not the same as that required for gasoline owing to the higher vapor pressure. Similar infrastructure exists to export LPG, but those facilities are currently fully utilized. There are plans to install a storage tank and other facilities necessary to export pentanes by marine tanker from the Port of Long Beach. However, construction has not started and it's not expected to be completed before 2004. The estimated marine loading capacity for pentanes is 8,000 barrels per day, beginning in 2004 at the earliest, or 37 MDTh/day.

The rail loading capacity also results in an additional constraint on the volume of pentane that can conceivably be sent to storage and returned for gasoline blending during the winter season. The pentane loading and unloading facilities are anticipated to have the same capacity of 10,000 BPD or 46.2 MDTh per day. However, the winter season is only one third as long as the summer season. Therefore, the seasonal storage option is limited by the volume of pentane that could be brought back during the winter production season, which is 10,000 BPD for 90 days. This then averages 3,333 BPD or 15.4 MDTH/day for each day during the 275-day summer production season. The infrastructure required at the potential storage sites outside California is not anticipated to be in place until 2004 at the earliest.

Each option for the excess pentanes will compete based on the price of natural gas versus the value for the pentanes in alternate markets. A summary of competing pentane disposition alternatives and associated limits is shown in the table below:

COMPETING PENTANE DISPOSITION ALTERNATIVES			
	Limit	Transfer	
<u>Refinery Substitution for Natural Gas</u>	<u>MDTh/day</u>	<u>Mode</u>	<u>Value set by:</u>
Burning in cogeneration plants and heaters	25.0		} Natural Gas Price
Hydrogen plant feedstock	<u>76.0</u>		
Substitution Limit	101.0		
<u>Export from Refineries</u>			
Seasonal Storage	15.4	rail	} Market Price less Transportation
USGC conventional gasoline blending	83.2	rail & marine	
Japan petrochemical feedstock	37.0	marine	
USGC petrochemical feedstock	83.2	rail & marine	
Total Export Limit	83.2	rail plus marine	

Given these criteria there is natural gas price high enough that will cause all of the excess pentanes to be substituted for natural gas. There are also limitations in the export infrastructure will also cause a certain volume of pentanes to be substituted for natural gas no matter how low the price is. In between these two extremes there are several threshold natural gas price levels that will set the volume of pentane substitution in refineries based on economics and physical limits.

The net pentane substitution is volume of pentanes substituted less the increased demand for purchased fuel. Using Purvin & Gertz' forecast for the value of pentanes in alternate markets, the net pentane substitution for natural gas in refineries was estimated for the years 2003 –2006 (see table below).

ESTIMATED NET POTENTIAL SUMMER PENTANE SUBSTITUTION				
	2003	2004	2005	2006
I. FIRST THRESHOLD PRICE				
Natural Gas Price* Less Than:	\$3.74	\$3.70	\$3.68	\$3.74
Net Potential Summer Natural Gas Substitution, MDTh/day	9.1	(1.7)	(3.2)	(3.7)
Natural Gas Price Equal to or Greater Than:	\$3.74	\$3.70	\$3.68	\$3.74
Net Potential Summer Natural Gas Substitution, MDTh/day	9.1	15.0	12.0	10.0
II. SECOND THRESHOLD PRICE				
Natural Gas Price Equal to or Greater Than:	\$3.99	\$3.94	\$3.92	\$3.99
Net Potential Summer Natural Gas Substitution, MDTh/day	55.3	66.1	64.6	64.1
III. THIRD THRESHOLD PRICE				
Natural Gas Price Equal to or Greater Than:	\$4.33	\$4.20	\$4.12	\$4.12
Net Potential Summer Natural Gas Substitution, MDTh/day	55.3	81.5	80.0	79.5
*Average summer burner tip natural gas price, \$/MM BTU (HHV)				

For natural gas prices less than the first threshold only the pentanes that cannot be physically exported would be substituted for natural gas in the refineries.

The first threshold natural gas price must reach before substitution in cogeneration units and other fired heaters becomes economic over USGC gasoline blending, but not high enough to be more economic than seasonal storage. Pentanes would first be sent to seasonal storage followed by the substitution for natural gas in refinery cogeneration units and fired heaters. The balance of the pentanes would be sold into the USGC gasoline blending market.

The second, and higher threshold natural gas price must be reached before pentanes begin to be substituted directly for natural gas as hydrogen plant feedstock, in addition to fuel, over the USGC gasoline market, but not high enough to be more economic than seasonal storage. In this case pentanes are first sent to seasonal storage. The balance of the pentanes is substituted for cogeneration, fired heaters and hydrogen plant feedstock.

When the third threshold natural gas price is reached all of the pentanes are substituted in the refinery.