UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Pacific Gas Transmission Company	)	Docket No. RP94-149-000
	)	

Economic and Environmental Effects of the 1993 PGT Pipeline Expansion: The Choice of Equalized versus Vintage Rates

Prepared Direct Testimony

of

Andrew J. Van Horn

Submitted on behalf of Southern California Edison Company

November 17, 1994

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Q. Please state your name, position and business address.

A. My name is Andrew J. Van Horn. I am a principal of Van Horn Consulting, 61 Moraga Way, Suite 1, Orinda, California 94563.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Southern California Edison Company, the holder of 200 MMcf/day (MMcf/d) firm capacity rights on the November 1993 expansion of the Pacific Gas Transmission (PGT) natural gas pipeline.

I. BACKGROUND AND QUALIFICATIONS

Q. Could you describe your professional qualifications and educational background.

A. Yes. For the past seventeen years I have specialized in energy and environmental economics, markets and regulation. I provide planning, technical and regulatory consulting services to the gas and electric industries, energy and technology-based companies, government agencies and research institutions. I have conducted analyses concerning the competitive interactions of natural gas, electricity, coal, technology and emission allowance markets, as well as assisting clients with electric and gas planning, regulatory, contractual and competition-related issues. To provide quantitative evaluations, I have developed and applied economic, engineering and financial models and compiled and analyzed extensive energy market and industry data. I recently directed the electric utility industry's integrated study of emerging emission allowance markets for the Electric Power Research Institute. Prior to founding Van Horn Consulting in 1987, I was a principal and director of Putnam, Hayes & Bartlett, an economic and management consulting firm. Prior to that I held positions as the director of energy systems planning and research at TERA Corporation and served as a research fellow in the Energy and Environmental Policy Center at Harvard University. I hold a B.S. degree in physics from Harvey Mudd College in Claremont, California and a Ph.D. in physics from the University of California at Berkeley.

Q. Have you testified previously?

A. Yes. I have testified as an expert economic witness before the California Energy Commission and in Superior Court in Alameda County, California. I have also testified concerning economic damages in litigations involving the alleged breach of energy-related and power purchase contracts.

II. SUMMARY AND CONCLUSIONS

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to identify and quantify the principal economic benefits of the 1993 PGT pipeline expansion (1993 Expansion) and to describe the implications of my analysis for the Commission's choice of "vintage" (incremental) or "equalized" (rolled-in) rates for shipments using the 1993 Expansion facilities.

A. Are you sponsoring any exhibits?

Q. Yes, I am sponsoring the following exhibits:

Exhibit SCE__(AVH-2) Interstate Pipeline Capacity into California

Exhibit SCE_(AVH-3) California Border - Henry Hub Price Spreads

Exhibit SCE_(AVH-4) Econometric Estimation of the California Border Gas Price

Exhibit SCE_(AVH-5) Actual and Predicted Values for the California Border Price of Gas

	FTS-1 Customers in California
Exhibit SCE_(AVH-23)	First Year Commensurate Benefits Test for PITCO Service
Exhibit SCE_(AVH-24)	1st Year Vintage vs. Rolled-in Rates as a Function of the Size of the PGT Expansion
Exhibit SCE_(AVH-25)	1st Year Marginal vs. Rolled-in Rates as a Function of the Size of the PGT Expansion

Q. Would you please summarize your testimony?

A. I have determined that there are substantial direct and indirect economic benefits that have occurred as a result of the 1993 Expansion. Viewed in the context of FERC's commensurate benefits test, the benefits of the 1993 Expansion far outweigh the costs of immediately moving from vintage to equalized rates for pre-Expansion customers (i.e., pre-November 1, 1993 customers) of PGT. Table AVH-1 shows the first year benefits to two categories of pre-Expansion customers. In both cases the aggregate benefits received from the 1993 Expansion exceed the extra costs to those customers who now pay lower rates on PGT's pre-Expansion facilities.

TABLE AVH-1
FIRST YEAR COMMENSURATE BENEFITS TEST RESULTS
FOR PRE-EXPANSION PGT CUSTOMERS IN CALIFORNIA
CHANGING FROM VINTAGE TO EQUALIZED RATES

	FTS-1 Service (4/MMBtu)	PITCO Service (4/MMBtu)
Gas-on-Gas Competition		
Direct Price Reduction	16.9	16.9
Economic Multiplier Effect	19.5	19.5
Fuel and Operating Benefits		
Direct Cost Reduction	2.7	1.6
Economic Multiplier Effect	3.1	1.8
Reduced Gas Supply Restructuring Surcharge	5.2	(2.8)
Less: Added Cost of Equalized (Rolled-In) Rates	(16.8)	(0.9)
Net Benefits (4/MMBtu)	30.6	36.1

It is important to note that the benefits of the 1993 Expansion flow to both new and old customers of the pipeline. Moreover, since Pacific Gas & Electric Company (PG&E) held the firm capacity rights on PGT's original facilities, a number of the ultimate consumers of gas now being transported on the 1993 Expansion are previous purchasers of gas from PG&E over the original facilities. Since PG&E has released about 40 percent of its capacity on the original facilities, there are also new 1994 customers who are currently enjoying lower rates by using released capacity on the original facilities than those customers of 1993 vintage who are paying higher rates for the same service on the 1993 Expansion.

Q. Are there benefits from the 1993 Expansion besides those that PGT shippers receive?

A. The benefits of the 1993 Expansion accrue not only to PGT shippers but to all gas consumers in California and the Pacific Northwest. My analysis shows that the enhanced competition made possible by the 1993 Expansion has reduced gas prices by about $0.169 for each MMBtu of gas entering California. Price reductions are also likely in the Pacific

Northwest, although of lower magnitude than in California. These direct benefits in turn multiply through the economies of these regions, generating further economic benefits. The 1993 Expansion will also facilitate the future improvement of air quality in California and the Northwest by allowing gas use to increase beyond the delivery capability of pre-1993 interstate capacity into California and, thus, to displace dirtier fuels that would be used in the absence of pipeline expansions after 1992.

Levelized annual benefits of the 1993 Expansion, including gas-on-gas competition benefits and the indirect benefits of the Expansion, are summarized in Table AVH-2 on the next page. This table also shows the net present value (NPV) of the 1993 Expansion benefits I have quantified. These shared benefits far exceed the costs of the 1993 Expansion and justify immediate roll-in of PGT's rates.

Q. Are there other conclusions the Commission should be aware of?

A. Yes. I have examined the marginal costs, as well as the potential "vintage" and "equalized" rates that a range of smaller and larger design alternatives to the 1993 Expansion would have required. I conclude that the particular expansion size that PGT planned was within the economically preferred range, given market demand at the time the project was subscribed and given the marginal costs and potential rates associated with both smaller and larger capacity additions that might have been selected instead of the 1993 Expansion.

Furthermore, PGT is now at a point in its expansion cycle where low cost, compression-only expansion is possible. The marginal costs of expansion above PGT's current capacity are closer to an equalized PGT rate than to the vintage rate proposed for the 1993 Expansion facilities. (These marginal costs are, in fact, below the equalized rate, which is below the vintage rate.) Thus, equalized, rolled-in rates would send a more accurate market signal regarding today's marginal cost of increasing capacity than would vintage rates for the 1993 Expansion facilities.

TABLE AVH-2
LEVELIZED ANNUAL AND NET PRESENT VALUE
OF THE BENEFITS OF THE 1993 Expansion
(Million Dollars)

Total Annual Levelized Benefits*	
Benefit	**(Million Dollars)**
Lower Gas Prices	404
Fuel Savings	6
Increased Service Reliability	4
Economic Multiplier Benefits	478
Air Quality Improvements**	58
Total Annual Benefits	**951**
Twenty-Year Present Value Benefits	
	(Million Dollars)
Net Present Value at 5% Discount Rate	12,716
Net Present Value at 10% Discount Rate	8,766

* Levelized benefits assume a discount rate of 10.0% per year, with benefits estimated over 20 years (1994-2013)

** Air quality benefits attributable to the 1993 Expansion begin about 1998.

Q. What are your conclusions regarding the choice of an equalized or a vintage rate structure for PGT?

A. My analysis supports the immediate roll-in of 1993 Expansion costs to create equalized rates for all PGT capacity holders. Equalized rates are strongly justified by four main conclusions:

! There are substantial net benefits provided by the 1993 Expansion, as shown in Table AVH-2.

! Even if the 1993 Expansion costs are rolled-in, there are substantial net benefits to pre-Expansion customers using PGT's original facilities. That is, for most consumers using gas transported over the PGT facilities that were in operation prior to November 1993, the benefits from the 1993 Expansion exceed the added costs to them of adopting rolled-in rates, as shown in Table AVH-1.

! Both the 1993 Expansion and the original PGT facilities operate in an economically and technically integrated manner, making the service provided on each indistinguishable. Thus, under incremental, vintage ratemaking, two prices are being charged for a single service. Charging multiple prices for the same service violates the principle of "equal price for equal service" and creates obvious inequities in this case, as well as confusion and inefficiency in the gas market.

! Many users of pre-1993 facilities are, in fact, indistinguishable from the users of Expansion facilities in terms of the timing (or vintage) of their initial demands for PGT's services. A number of "old" PGT non-core end-users now receive service over the 1993 Expansion, while many "new" PGT end-users have recently gained access to the pre-Expansion PGT capacity made available under capacity release. To arbitrarily confer vintage rights and lower prices to some of these customers, but not to others receiving identical service, is unfair. This situation is clearly inconsistent with the Commission's regulatory goals and, by itself, argues for equalized rate treatment for all customers.

Q. Would you please discuss each of these conclusions in detail, including an explanation of the theory behind your analysis, the analytic approach and data sources you used.

A. My discussion of these issues is contained in the next four sections, as follows: III. Direct Consumer Benefits from Gas-on-Gas Competition; IV. Indirect Economic Benefits to the California Economy; V. Environmental Benefits; VI. Commensurate Benefits to Pre-Expansion Customers and Examples of Market Inequities from Vintage Rates on PGT; and VII. Economic Perspective on the Size of PGT's 1993 Expansion.

III. DIRECT CONSUMER BENEFITS FROM GAS-ON-GAS COMPETITION

Q. What are your observations concerning the competitive effects of the PGT expansion?

A. My first observation is that the expanded PGT pipeline capacity has had a significant effect upon reducing natural gas prices paid by California consumers. While I empirically show this for the 1993 PGT Expansion, I also demonstrate the basic principle that competition is enhanced by expanding capacity to competitive sources of supply. In particular, my analysis demonstrates that the 1993 Expansion has resulted in measurable and significant reductions in delivered gas prices to all California consumers.

Q. What are the economic principles behind your observations?

A. The economic theory is based upon the principle of location rent. Location rent is the difference in regional commodity prices that results from different transportation costs or transportation bottlenecks between points of production and the marketplace. The location rent principle explains the reason that the commodity price of milk produced in central Wisconsin must be less than the commodity price of milk produced near New York City in order to compete on an equal delivered price basis in New York City.[1/]

Q. How does a change in pipeline capacity affect location rent and how does this directly affect consumers of natural gas?

A. The location rent associated with natural gas markets is caused by constrained transportation system capacity. By constrained capacity, I refer to the inability of the pipeline system to quickly change its capacity in response to changes in demand. Added pipeline capacity that increases access to low cost gas production areas will tend to encourage competition and create a more stable marketplace with lower consumer prices.

Q. You state that there is a high amount of location rent in the natural gas industry. What

[1/] The situation is complicated by the presence of other markets closer to Wisconsin, where a producer would try to sell his milk in order to maximize his revenues net of all transportation costs, (i.e., using the terminology of gas markets: to maximize "netback.")

does this imply?

A. Natural gas is unlike many other commodities. For many industries the location rent is proportional to the marginal cost of transportation (i.e., mileage or travel time). Added transportation capacity has little effect upon the location rent. This is because there are relatively low entry barriers associated with increasing transportation capacity for most commodities. For example, because it is easy to add more trucks to meet shipping demand, trucking capacity has little effect upon trucking rates and on the location rent for commodities shipped by truck.

On the other hand, there are significant barriers to entry to the natural gas pipeline industry caused by the large capital requirements and economic and environmental regulations associated with constructing new capacity. Pipeline capacity that is built and utilized over the long run should tend to reduce both natural gas commodity prices and average pipeline transportation prices below what they would otherwise have been in the absence of the added capacity.

Q. Have you developed a hypothesis for gas prices that incorporates economic principles and market conditions, in order to explain differences between delivered gas prices in various regions of the United States?

A. Yes. Over the last ten years great strides have been made in the United States to create a more competitive North American natural gas market. Changes in regulation have decreased regulatory barriers to competition, and new pipeline facilities have provided greater access to previously constrained, low cost gas supplies.

Using statistical techniques, I have developed and validated an equation that relates monthly gas prices at the California border from 1990 through 1994 to monthly gas prices at the Henry Hub in Louisiana and to the following key monthly variables affecting the California gas market: gas consumption in California, gas production within California, net withdrawals from storage in California, and the interstate pipeline capacity into California.

Q. Please describe the Henry Hub gas price index.

A. The Henry Hub index is the index of gas prices used for trading gas market futures on the New York Mercantile Exchange (NYMEX). Since early 1990, when this market index began, it has been used as a base from which to measure the effects of regional price conditions. The difference between a regional gas price and the Henry Hub price is referred to as the basis difference or basis spread.

Q. Please describe your equation and explain how it represents competitive market behavior.

A. The essence of a competitive market is the ability of each buyer to choose the most competitively-priced gas supply that can be delivered at any point in time. My hypothesis is that if most gas behaves like a commodity in a competitive North American gas market, the price of gas in the California market will be determined by the national commodity price and various structural market factors, such as existing contractual obligations and transportation tariffs unique to California's location, as well as by the relative capability of California buyers to displace more expensive supplies with less expensive supplies.

The monthly contract price of gas at the Henry Hub reasonably represents a national commodity price of gas. Other variables, specific to the California market, would describe underlying California market fundamentals that cause differences with respect to the Henry Hub, such as the "slack capacity" each month on the interstate pipelines entering California.

Q. What do you mean by "slack capacity?"

A. Slack capacity is a measure of the ability of a California consumer to access different competitive supplies and freely move purchases between supply basins or pipelines in response to price changes. When all interstate pipelines serving California are filled, then both the slack capacity and consumer flexibility to switch pipelines will be lowest. When there is slack capacity available, the buyer can more readily shop for a better price.

Q. How have you determined slack capacity?

A. Four quantities together determine the slack interstate pipeline capacity to California each month: (1) the interstate pipeline capacity into California plus (2) intra-state gas production plus

(3) net withdrawals from underground storage minus (4) statewide gas consumption. An econometric estimation, using Californian market data and this definition of slack capacity, has enabled me to test whether or not the level of slack capacity perceived by market participants has permitted California prices to vary from the national market price.[2/]

Q. What is an econometric estimation?

A. An econometric estimation combines statistical data analysis methods with economic principles, in order to test hypotheses about market behavior. Econometric estimation methods, such as linear regression, allow me to examine market data and to determine whether the behavior of the data over time can be explained by economic concepts and relationships.

Q. Assuming you can develop a relationship or equation that explains the California border price over time, how can this relationship be used to demonstrate the effects of added pipeline capacity?

A. Competition can be inhibited by pipeline capacity constraints. From 1988 through 1991, the interstate gas pipelines serving California operated at high load factors, keeping slack capacity at low levels, and, thus, diminishing gas-on-gas competition. Starting in 1992, new interstate capacity was added, potentially increasing the slack capacity available and enhancing competition between alternative gas suppliers trying to serve the California market. Exhibit SCE _(AVH-2) illustrates the changes in interstate pipeline capacity into California and the variations in slack capacity since 1990.

If the new pipeline capacity has, in fact, led to enhanced competition, then lower prices should be observed after capacity additions. A regression equation can statistically estimate the parameters influencing the behavior of California's border prices. Then, the gas price benefits of the capacity additions can be estimated by calculating the price "with" the

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[2/] The slack capacity concept simply means that a local demand will be satisfied through a combination of local production and draw from inventories, with any excess being imported from other areas. This is conceptually the same framework that is used to define a location quotient or self-sufficiency ratio. For a more detailed discussion, see Walter Isard, *Methods of Regional Analysis*, MIT Press, 1960 .

capacity addition and then "without" the capacity addition. The difference represents the price benefit of the added capacity.

Q. Have you tested your hypothesis against empirical data?

A. Yes. I tested for a direct relationship between the variables described above and delivered gas prices at the California border, using historical data, including the most recent data available to me. I also examined whether there is any observed relationship between added pipeline capacity and the seasonal stability of gas prices.

Q. How did you test the relationship between added pipeline capacity and delivered gas prices?

A. I initially examined the trend over time between interstate pipeline capacity serving the California market and monthly gas prices at the California border between 1990 and 1994. I also compared California border prices against prices in other regions. If bottlenecks or capacity constraints have contributed to higher payments to gas producers, then, the addition of new pipeline capacity would cause a decline in the net price paid by consumers in California relative to the prices paid in other markets.

Q. What are the results of your analysis?

A. Exhibit SCE__(AVH-3) compares border prices in California relative to Henry Hub prices from 1990 to the present, with using data from the industry publication *Gas Daily*. It is obvious from Exhibit SCE__(AVH-3) that significant shifts in prices have occurred when more interstate pipeline capacity was added to California after 1990. Table AVH-3 below shows the aggregate trends in these prices, as well as in slack capacity entering California.

TABLE AVH-3
THE COMPONENTS OF CALIFORNIA SLACK CAPACITY (EXCESS DELIVERABILITY) AND THE CALIFORNIA BORDER PRICE RELATIVE TO THE HENRY HUB PRICE*

Market Parameters	1990-92	1991-92	1992-93	1993-94
	------ Billions of Cubic Feet per Day -----			
Interstate Pipeline Capacity	5.3	5.6	6.4	6.9
Plus: California Gas Production	1.0	1.1	0.9	0.9
Plus: Withdrawals from Storage	0.0	0.1	0.0	0.0
Minus: Consumption	5.1	5.2	5.1	5.3
Equals: Slack Capacity	1.3	1.4	2.2	2.5
	----- Dollars per Million Btu ----			
California Border Price	2.16	1.87	2.23	2.13
Minus: Henry Hub Index Price	1.56	1.48	2.12	2.16
Equals: Basis	0.59	0.38	0.11	(0.03)

* To avoid missing or incomplete years, data are tabulated from July through the following June.

Q. Are the observed changes in relative gas prices explainable by economic principles and supported by statistical analysis?

A. Yes, they are. Exhibit SCE_(AVH-4) lists the results of a regression analysis in which the monthly movement in the California border price between 1990 and 1994 is predicted in relation to the Henry Hub price and to the monthly amount of slack interstate pipeline capacity into California. The extent of the direct relationship is examined statistically in Exhibit SCE_(AVH-4) and illustrated graphically in Exhibit SCE__(AVH-5). The equation shown in Exhibit SCE (AVH-4) constitutes a simple economic transportation model in which the effective regional delivered price moves in step with the national commodity price and in proportion to the amount by which transportation capacity exceeds consumer demand at any given time. For this analysis, ordinary least squares econometric estimation was employed. All of the coefficients are statistically significant.

Q. How well does the equation shown in Exhibit SCE_(AVH-4) fit the monthly variations in the California border price from 1990 to 1994?

A. Exhibit SCE___(AVH-5) shows the wide monthly swings in California prices over this period. (See the solid line). The econometric equation has been used to estimate the price in each month, as illustrated by the dashed line. As can be observed, the equation effectively explains most of the substantial variation in monthly California gas prices over the last four years, using the most recent data available.[3/]

Q. Would you please provide an interpretation for the statistics given in Exhibit SCE (AVH-4).

A. The constant 1.141 can be interpreted as a $1.141/MMBtu fixed charge for all of the costs and contractual obligations that are not specifically covered by the other parameters. The coefficient multiplying the Henry Hub price is 0.747. This means that for each ten cent change in the Henry Hub price the California border price has changed by about 7.5 cents. In other words, California Border prices have not shown quite the same degree of month-to-month volatility as Henry Hub prices.

Q. How do you explain that?

A. As I stated earlier, one reason that the California price does not precisely track the Henry Hub price is that the California market has access to different supply basins, and buyers in California have been able to use the slack interstate pipeline capacity entering California to negotiate lower and more stable prices.

Q. What is the coefficient on the "slack capacity" variable and what does it mean?

A. The coefficient on the slack capacity variable is negative 0.221. This means that for each

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3/ A four-year period was used to ensure that seasonal variations were reflected by using complete years of monthly data. 1990 was selected as the first year due to the initiation of the NYMEX index in that year.

million MMBtu/day increase (i.e., approximately 1.0 Bcf/day) in pipeline capacity to California between mid-1990 and mid-1994, a 22.1 cent decrease in the price of natural gas has occurred relative to the price that would have been paid at the California border in the absence of the capacity addition. Thus, the combined effect of the 1.04 Bcf/d Kern and Transwestern capacity additions in 1992 has been to lower border prices by about 23.3 cents per MMBtu to all California consumers.

Q. What has been the effect of the 1993 Expansion on gas prices?

A. The effect of the 0.766 Million MMBtu/d (0.755 Bcf/d) PGT pipeline expansion has been to reduce the average gas price at the California border by approximately 16.9 cents below what the price would have been without the 1993 Expansion.

Q. Stripped of econometric or statistical jargon, how do you explain these price reductions?

A. These price reductions occurred because each of these expansions provided greater access to competitive supply sources. Consumers are now better able to shop for the best gas price, because they are now less limited by pipeline capacity.

Q. How does one use these results to compute the total consumer benefit from increased gas-on-gas competition caused by pipeline expansions into the state?

A. The total dollar benefits of these pipeline additions are obtained by multiplying the change in price times the statewide volumes of purchased natural gas. In the case of the 1993 Expansion this benefit amounts to 354 million dollars in 1994, calculated as the product of $0.169/MMBtu times the 1993 California Gas Report's projected 1994 statewide gas consumption of about 2.1 billion MMBtu. Total dollar benefits in succeeding years are calculated as the sum of the products of $0.169/MMBtu and a projected statewide gas consumption for each future year.

Q. Why should these gas-on-gas competition benefits continue into the future?

A. There are numerous reasons why price reductions due to the heightened competition provided by the 1993 Expansion will continue throughout the life of the 1993 Expansion facilities. These include:

(1) A demonstrated Canadian willingness to compete in the U.S. gas market. In particular, Alberta supplies have provided the lowest-priced, out-of-state gas available to Northern California consumers since 1988.

(2) Large Canadian reserves of gas with acknowledged low production costs.[4/]

(3) The current levels of utilization of the 1993 Expansion and of the overall PGT pipeline demonstrate that the Canadian supplies are competitive. Purchasers now transporting Canadian gas over PGT have displaced higher-priced U.S. gas supplies that would otherwise have been delivered to California over other interstate pipelines.

(4) The 1993 Expansion adds to the capacity serving California and to aggregate slack capacity, thus encouraging competition, while permitting greater access to low-priced Canadian supplies.

Q. Are there other measures of slack pipeline capacity that you might have chosen instead of the sum of monthly variables applied in Exhibit SCE_(AVH-4)?

A. Yes. The measure of slack capacity I have used to derive the equation given in Exhibit

SCE___(AVH-4) is based on the amount by which interstate pipeline capacity serving California exceeds California natural gas demand, after accounting for the effects of California gas production and withdrawals from underground storage within the state.

I have also examined an alternative measure of slack capacity based upon pipeline throughput on interstate pipelines serving California. In this instance, slack capacity is defined as the difference between maximum observed pipeline throughput and the recorded monthly pipeline throughput. When this alternative measure of slack capacity is substituted into the equation, as shown in Exhibit SCE_(AVH-6), the results are essentially unchanged. Although I

[4/] See, for example, "Natural Gas Market Assessment: Natural Gas Supply Western Canada," National Energy Board, November 1993. ISBN 0-662-21203-7.

believe the first definition of slack capacity is a more precise definition,[5/] the fact that both measures yield similar results supports my conclusion that the market perception of the availability of slack capacity permits substantial gas-on-gas competitive benefits that can not be explained as happenstance.

Q. Please explain how you have accounted for factors such as seasonality and the weather in your analysis.

A. My behavioral approach implicitly incorporates the impact of seasonality and weather conditions. When either of these change, the national (Henry Hub) price and the statewide consumption explicitly included in the model are each affected. These, in turn, lead to changes in the market's perception of slack capacity and the resulting competitive California border price. Using seasonal dummy variables in the equation is an alternative method that might be used to suggest the magnitude of monthly gas price fluctuations. However, the behavioral approach that I used is preferable.

Q. Why is that?

A. Because, unlike approaches using dummy variables, my method accounts for instances where, for example, California has an unusually warm winter with lower regional consumption and lower prices. In my approach physical quantities are used to reflect continuing changes in the market rather than dummy variables that start or stop at one point in time and that, by themselves, have no explanatory power. I have not needed to resort to using dummy variables because of the robustness of the statistical fit I observed.

Q. Realizing that the 1993 Expansion has been operating for under one year, is it possible to quantify the specific impact that the PGT pipeline has had upon California gas prices, as opposed to the impact that expanding capacity in general has had upon gas prices?

[5/] The alternative measure of slack capacity based on the throughput of pipelines that serve California provides a less rigorous definition than the measure I have chosen, because the available data on pipeline throughput includes all throughput, including natural gas that is delivered to states along the pipelines serving California.

A. By itself the equation in Exhibit SCE__(AVH-4) does not explicitly distinguish between the individual effects on the California border price of each pipeline capacity addition that has occurred since mid-1990. However, the data defining the monthly slack capacity explicitly incorporates each capacity addition, as it occurred. I have also performed an additional "before and after" analysis to examine whether the 1993 PGT Expansion reduced prices more or less than the 1992 expansions of interstate capacity to California.

Q. Please explain this additional analysis.

A. To test the periods before and after the 1993 Expansion, I estimated a modified Exhibit SCE__(AVH-4) equation with the same data definitions but only using data through October 1993, before the PGT pipeline expansion began service. I did this to uncover any "before Expansion" versus "after Expansion" price benefit differences, as well as to explore the robustness of the equation structure.

My results for this analysis are shown in Exhibit SCE__(AVH-7). In comparing this table with Exhibit SCE__(AVH-4), note that the overall fit and estimated parameters are quite similar. This confirms that the equation structure represents the behavior of the market. In the shorter-interval estimation, the value of the intercept is about one percent less, while the value of the Henry Hub coefficient is nearly the same. The estimated coefficient on the slack capacity variable is about thirteen percent less in the Exhibit SCE__(AVH-7) equation covering only the period prior to the 1993 Expansion than in the Exhibit SCE__(AVH-4) equation that includes periods both before and after the 1993 Expansion went into service.

Q. What is the meaning of these numbers?

A. This difference suggests that the 1993 Expansion may have had an even larger impact on California border prices than the earlier pipeline expansions. However, the difference is also relatively small and is not of statistical significance. This analysis provides no evidence of a diminished impact upon prices from the 1993 Expansion relative to the earlier interstate expansions into California. This result is also consistent with theory. Theoretically, if the supplies on the 1993 Expansion, Kern River, Transwestern and El Paso expansions are each displacing Permian or other Southwest supplies at the margin, then their benefits should be about the same per MMBtu. This analysis confirms this hypothesis.

Q. Would you please discuss your analysis of the average California borderXChicago citygate[6/] and Henry Hub price spreads for equivalent periods before and after the 1993 Expansion?

A. I have examined these price spreads for the November 1993 through October 1994 period during which the 1993 Expansion has been operating, which is the longest post-expansion period for which natural gas price data is currently available. I then contrasted these averages with the average price spreads for the twelve equivalent months immediately before the 1993 Expansion's in-service date.

Q. What do you conclude from this analysis?

A. As Exhibit SCE__(AVH-8) shows, the average price spread between California border prices to end-users and Chicago LDC prices improved by 13 cents after the 1993 Expansion was placed in service. The spread between the California border price to end-users and the Henry Hub price improved by 14 cents. For the spreads on California border prices for utility contracts, the improvements after the 1993 Expansion in-service date were 8 cents relative to Chicago LDC prices and 10 cents relative to Henry Hub prices. The most plausible explanation for these regional shifts is that the 1993 Expansion increased gas-on-gas competition, lowering the California border price.

Q. If California had added 7,500 MMcf/d instead of pipeline capacity in the range of 500 to 1500 MMcf/d of pipeline capacity, would your regression equation results, shown in Exhibit SCE_(AVH-4), still have been valid?

A. My representation of gas-on-gas competition by a linear regression equation using market

[6/] I have looked at Chicago citygate prices, because, like the Henry Hub, the Chicago market has access to several gas supply sources and competing pipelines.

variables must satisfy two market tests. The first test is that each capacity addition be economic and useful. If buyers are willing to subscribe to and use a pipeline's new capacity, whether it is 750 MMcf/d or 7,500 MMcf/d, then this test is passed. The second test is that each capacity addition represents a marginal addition to the market served and, therefore, does not subject the market to a structural change that would change the rules of competitive behavior. It is unlikely that a 7,500 MMcf/d capacity expansion would pass this second test for all of its capacity.

My empirical analysis demonstrates that all of the post-1990 interstate pipeline capacity additions to California shown in Exhibit SCE___(AVH-2), including the 1993 PGT Expansion, which represents about 10 percent of today's interstate capacity entering California, have been economically useful and have led to measurably reduced gas prices. The evidence demonstrates that all of these pipeline additions have simply, and effectively, promoted gas-on-gas competition and reduced gas prices in proportion to the slack capacity created by each.

Q. Why did you use the *Gas Daily* California border price, as opposed to some other price measure, to determine the California market impact of these pipeline expansions?

A. *Gas Daily*'s monthly contract California border price has been used increasingly as a basis upon which to price unbundled and partially-unbundled transactions throughout the period of my market analysis. As competition has increased in the post-Order No. 636 environment, it is now widely used for this purpose in all segments of the California market. The monthly contract California border price is also one of the few widely recognized and consistently recorded price measures for which a long enough monthly time series exists to estimate a statistically significant price response to California's pipeline expansions. Because it polls the same users, the *Gas Daily* price tends to move very closely with other California border prices, such as those published by *Inside FERC*.[7/] Exhibit SCE_(AVH-9) compares these monthly prices.

Q. But even today, aren't there differences in the price paid for gas at the California border

[7/] Substituting *Inside FERC* price data to estimate coefficients, as in Exhibit AVH-3, yields very similar results.

depending on the delivery point or the identity of the buyer?

A. Having said that the California border price is the basis on which transactions are priced does not mean that pricing differences do not exist at the border. For example, border prices for large volume utility sales might be somewhat lower than prices for sales transactions to end-users whose volumes on average are smaller. And the California Public Utility Commission's (CPUC) "cross-over" ban means that natural gas shipped down the 1993 Expansion may need to be priced cheaper at Malin for Northern California sales than natural gas flowing through Topock (or other delivery points), in order for the expansion sale to compete on an equal basis at the customer's burnertip. Of course, the differential pricing of an equivalent transportation service caused by the CPUC's "cross-over" ban distorts the market, causing efforts by shippers to avoid paying the higher price for shipments on PG&E's Line 401. Such efforts to avoid the CPUC's distortion of market prices have been referred to as the "Klamath Falls Shuffle" and the "Stanfield Two-Step," and they unnecessarily increase the transaction costs of delivering gas via the Expansion.

Nevertheless, there is no reason to believe that the pricing response to the 1993 Expansion in these kinds of transactions is any different than I have estimated. To illustrate this point, I have used a data series for California border prices to utilities to re-estimate my basic equation with the same independent variable definitions as in my basic Exhibit SCE__(AVH-4) equation.

Q. What does this re-estimation using different data conclude?

A. In this new equation, shown in Exhibit SCE__(AVH-10), the coefficient on slack capacity is -0.2214. This is nearly the same as the coefficient in the basic Exhibit SCE___(AVH-4) equation.

Q. How do you contrast your analytic approach with that of the Data Resources, Inc. (DRI) and Decision Focus, Inc. (DFI) consultants, who have offered testimony in support of PGT's filing in this case?

A. The PGT benefit forecasts are derived from complex gas market simulation models, which evaluate detailed production cost data for major U.S .and Canadian supply areas, as well as pipeline capacity, transportation rates and demand estimates for each major U.S. market region. The models simulate future national supply/transportation cost and demand equilibrium conditions that could result under various pipeline capacity and demand scenarios. The results of these models are consistent with expected competitive market behavior and, in general, represent reasonable estimates of the differences in markets with and without the 1993 Expansion.

In contrast to the national models, my analysis has focused on the California market. I have sought to establish in a simple, direct and verifiable way the magnitude of gas-on-gas competition benefits that have already occurred at the California border as a result of the recent interstate pipeline expansions into the state.

All of the analyses of the 1993 Expansion, including this study of actual market performance, show that increased access to the large, low cost Western Canadian Sedimentary Basin lowers the relative marginal and average costs of the gas that is expected to supply the California market. All show enhanced competitive impacts on other producing areas in the United States due to expanded PGT capacity, as Southwest supplies compete in other regional markets after being displaced by Canadian gas in California.

Q. Does your analysis confirm the magnitude of the gas-on-gas competition benefits that the PGT modeling consultants have projected?

A. In general terms, my results using historical data corroborate the results for future benefits projected by the large computer models. Summarizing FERC (ARD-4) No. 19 data request, DFI initially estimated the California gas-on-gas competitive benefits of the 1993 Expansion to range between 5.0 and 9.5 cents per Mcf, and DRI estimated the benefits at 7.4 to 10.0 cents after 1995. However, a revised analysis by DFI, which corrected the volume of simulated gas flows on PGT in the "without expansion" base case to about 1030 MMcf/d, projects that the benefits of the expansion will range over time between 9.1 and 14.8 cents per Mcf. An additional sensitivity analysis by DFI which simulated flows of about 1960 MMcf/d over a PGT pipeline with a capacity of 2042 MMcf/d at Malin projected an average California price reduction of 11.5 to 20.4 cents per Mcf. Finally, an unconstrained PGT capacity analysis performed by DFI has estimated that California price reductions ranging from 20 to 38 cents per Mcf could be obtained through further expansion of the PGT pipeline to a capacity of about 3000 MMcfd. My empirical analysis shows that the actual competitive benefits to date have been 16.9 cents per MMBtu.

Q. Are you aware of any other estimates of gas-on-gas competitive benefits that have been statistically computed for the California region that would corroborate your estimate of benefits from gas-on-gas competition?

A. Yes, I am. Paul R. Carpenter of Incentives Research, Inc. in Boston has estimated gas-on-gas competition benefits for the 1992 Kern River pipeline. Scott A. Kominiak of Pacific Gas & Electric Company (PG&E) has estimated gas-on-gas competition benefits from the combined pipeline capacity expansions to the San Juan basin. Carpenter estimated that the Kern River and Mojave Pipelines, which added 700 MMcf/d of new capacity into California, caused a 23.5 cent reduction per MMBtu in gas price.[8/] This computes to 34 cents for each million MMBtu of added pipeline capacity, which is almost seventy percent larger than my estimate. Kominiak estimated that the Transwestern expansion of 0.345 Million MMBtu per day (indirectly supported by the Kern River expansion which occurred at the same time) caused a 14 cent per MMBtu reduction in gas price.[9/] Kominiak's results would indicate a gas-on-gas competitive impact of between 14 and 40 cents per Million MMBtu of added pipeline capacity, depending on

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8/ Paul R. Carpenter, "The Competitive Origins and Economic Benefits of Kern River Gas Transmission." February 1994. Filed as an ex parte communication to the California Public Utilities Commission (CPUC), April 1994.

9/ Scott A. Kominiak, "The Price Effects of Enhanced Competition in the U.S. Southwest Supply Markets Due to the Transwestern Expansion." PG&E Rebuttal Testimony in Application No. 93-04-011. CPUC, June 1994. This testimony shows an average of about a 174/MMBtu decline in Permian prices, along with a 10.64 per MMBtu decline in San Juan prices.

the relationship between the Kern River and Transwestern expansions. My results are nearly the same as the low end of the Kominiak analysis.

Q. How would you explain the difference between the lower forecasts of gas-on-gas competition benefits shown by the DRI and DFI models and the higher estimates that the Carpenter and Kominiak analyses provide?

A. The differences are due to the perspectives of the individual models. As I stated before, the DRI and DFI models make national forecasts conditioned upon national constraints and multi-state regional conditions. Their perspective on the California market is based on these national trends and relationships, rather than solely focusing on trends and relationships that are specific to the California market. To calculate their price benefits, they examine national scenarios "with" and "without" the 1993 Expansion into future years and take the difference between the scenarios. Updating the data and calibrating such models to accurately reflect the behavior of a particular market can be a time-consuming and laborious process.

On the other hand, my analysis and those of Carpenter and Kominiak are specific to this state and evaluate the actual price behavior of competitors serving the California market. The historical analyses are more reflective of the gas-on-gas competitive benefits that have occurred in California as a result of recent interstate pipeline expansions. My analysis also incorporates more recent data than either the DFI or DRI models and measures actual market behavior in California, rather than a range of potential behaviors based on a forecasted nationwide response.

Q. You have also examined California relative to the nation. Could these statewide averages be the result of other industry factors or circumstances particular to this one state, such as CPUC regulatory initiatives?

A. That is unlikely, particularly given the statistical significance and the behavioral response exhibited by my regression equations. Of course, the removal of regulatory constraints can encourage competitive market behavior, but without the physical pipeline capacity to let market forces work, prices would have been higher, as my analysis demonstrates. Additionally, other market data demonstrates a similar effect of adding pipeline capacity.

Q. Would you please describe this other data.

A. Exhibit SCE__(AVH-11) shows the relationship between California border and Chicago end-user citygate prices, as reported by *Gas Daily*. *Gas Daily* contract prices show the prices paid for contract gas deliveries in the coming month. For contracts made during the two-year period May 1990 through April 1992, this spread (i.e., the premium paid by California consumers) averaged +40 cents. After the Transwestern and Kern pipelines went fully into service about May 1992, increasing pipeline access between California and the Rocky Mountain and San Juan production areas, the border price spread significantly improved to an average of about -2 cents for May 1992 through October 1993. Since the PGT pipeline began full operation, the contract price spread has improved a further 17 cents to an average of -19 cents.

Note the large negative price spread for contracts made for February and March 1994. This reflects the higher Chicago price in response to a severe cold spell in the Northeast United States. At that time, the Henry Hub prices increased, from $2.08 in January to $2.39 in February. However, the slack pipeline capacity into California, including capacity releases on PGT, shielded the California marketplace from the price swings which occurred in other parts of the nation this past winter.

Q. How much of this regional benefit is net of the cost of the 1993 Expansion?

A. Since I am analyzing California border prices, which include interstate transportation costs, the amount is net of 1993 Expansion costs and thus, represents a net consumer benefit at the California border.

Q. What about stranded capacity costs?

A. I would differentiate between two types of stranded pipeline capacity. There is a type of non-economic stranded capacity, such as a rail spur that goes to a ghost town. That type of capacity cannot increase competition or provide any other foreseeable economic benefit. It is stranded in every sense that the word implies.

However, most so-called stranded pipeline capacity is of an economic nature. When capacity is added to a pipeline system, throughput levels on some pre-existing lines or segments may decline when gas buyers are able to find alternative sources and transportation route combinations that lower their delivered gas cost. The capacity of the lines or segments that experience lower throughput can be referred to as stranded, if their market value is reduced below their ratemaking book value. Since the addition of the 1993 Expansion to the pipeline system serving California, this so-called economic stranded capacity has been alleged on the El Paso (EPNG) and Transwestern (TWPL) pipelines. (See Exhibits SCE__(AVH-12) and SCE (AVH-13), which plot load factors for the EPNG and TWPL before and after the 1993 Expansion.) Nevertheless, EPNG and TWPL capacity, even if not physically used as before, still performs a valuable economic function by contributing to the slack capacity that forces all pipelines and gas production regions (including the Canadians and PGT) to compete more intensely. The net result of this increased competition has been to lower the cost of natural gas to all consumers at the California border, as my analysis shows.

Q. Do you have any other examples using pipeline-pipeline comparisons in other parts of the nation?

A. Yes, I do. Exhibit SCE__(AVH-14) illustrates the impact of the Iroquois pipeline on the Northeastern natural gas market. I have plotted the price of gas on the Tennessee pipeline relative to the Henry Hub price. The Tennessee pipeline is a primary supplier to the Northeastern market. If transportation bottlenecks and location rents existed, then the added capacity of the Iroquois pipeline should have lowered prices on the Tennessee pipeline, when Canadian gas began flowing to the Northeast via Iroquois. For contracts made during the June 1990 through October 1992 period, the (Tennessee-Henry Hub) price spread averaged -9 cents. When the Iroquois pipeline reached full operation in about November 1992, the price of Tennessee gas dropped. The November 1992 through October 1994 contract price spread has averaged -16 cents, a 7 cent improvement over the previous interval. This 7 cent average price improvement is statistically significant.[10/] Because of the new Iroquois pipeline, gas suppliers selling through the Tennessee pipeline were forced to lower their prices to maintain their market share. Apparently, gas-on-gas competition also works outside of California, when transportation capacity constraints are relieved.

Q. What portion of the benefits are due to a better mix of lower cost gas rather than to added pipeline capacity?

A. I object to the use of the term "lower cost gas," because this concept is not entirely consistent with that of competitive pricing. It would be clearly irrational for regional producers to sell their gas at anything but the highest possible price, so long as that price is above their marginal production costs and above what the producers could obtain from alternative buyers. Total production cost is largely irrelevant, except in relation to decisions about beginning or increasing production from economically marginal wells or fields. To illustrate: If I pick an ounce of gold off the ground at no cost, I will sell it at exactly the same price as an ounce of gold mined at great expense. So it is with natural gas.

Q. In that case, how much of your calculated result is due to what is commonly called increased gas-on-gas competition?

A. Essentially all price reductions are the result of increased competition among gas producers and holders of pipeline capacity. Both are operating in a restricted marketplace, and it is economically rational that each would lower prices to maintain or increase their market share. Because commodity prices typically account for about two-thirds of the delivered price of gas, gas-on-gas competition has the potential for proportionately higher impact than pipeline-to-pipeline competition.

[10/] I conducted a simple statistical test (the t-test) to determine the likelihood that these price differences did not happen randomly. Comparing the Tennessee basis for two full years (24 months) before and after the November 1992, effective start date of the Iroquois pipeline, the t-statistic of 4.94 indicates a 99.9% probability that the price differences were not random.

To demonstrate the effect of increased pipeline capacity on gas-on-gas competition as separate from pipeline-on-pipeline competition, I draw your attention to Exhibit SCE__(AVH-15), which dramatically illustrates how increased pipeline capacity to the San Juan basin and the addition of the Kern River pipeline in early 1992 reduced the relative price from the competing (but otherwise separate) natural gas from the Permian basin. Because this comparison does not include transportation costs to California, the figure illustrates the impact of pipeline expansion on gas-on-gas competition, as distinct from pipeline-to-pipeline competition. It also should be noted that the Permian Basin has been a marginal supply source for California, and in order to compete with Canadian, San Juan and Rocky Mountain supplies, its prices have had to decrease.

Q. What do you conclude from Exhibit SCE_(AVH-15).

A. From May 1990 through April 1992, the average spread or basis difference between Permian and Henry Hub supplies was -5 cents. From May 1992 until November 1993 (the date of the 1993 Expansion) the price spread was -21 cents, representing a 16 cent lowering of relative Permian prices below the earlier period. It is unlikely that a shift of this magnitude and consistency could have occurred randomly, and a simple statistical test (the t-test) before and after May 1992 confirmed this. A logical economic interpretation is that Permian prices were driven lower by the competing pipeline expansions that were fully in service in May 1992, giving greater access to the San Juan, Rocky Mountain and Western Canadian supply basins.

During the May 1992 through October 1993 period, the average Henry Hub price increased by $0.56/MMBtu over the May 1990 through April 1992 period. If the pipeline expansions had not occurred, the average California border price predicted by the regression equation given in Exhibit SCE__(AVH-4) for the periods in question would have increased by $0.42/MMBtu (0.75 x $0.56 Henry Hub price increase) due to changes in the Henry Hub gas price. Instead, the average California border price actually rose by only $0.14/MMBtu during the period. The gas-on-gas competition benefit of the California pipeline expansions, measured by increased slack capacity, and which provide enhanced access to low cost supply basins, was an important factor in lowering prices in the Permian Basin and holding the average California border price increase to a fraction of the average national price increase that occurred.

Q. Are there any resource or cost constraints that might reduce the predicted benefits of increased gas-on-gas competition from the 1993 Expansion over time?

A. While resource and deliverability constraints have the potential to restrict competition, the 1993 Expansion accesses the acknowledged largest and lowest production cost basin in North America, i.e., the Western Canadian Sedimentary Basin. The reserve base of 47 Tcf of remaining connected reserves, 22 Tcf of unconnected reserves and 114 Tcf of undiscovered potential reserves is expected to remain cost competitive well into the next century.[11/] Thus, it is reasonable to expect that the competitive benefits of the 1993 Expansion will continue well beyond a 20-year planning horizon.

Q. Would you expect that the PGT pipeline, which has access to the abundant, low cost Canadian gas supplies, might have the same effect as the San Juan expansions, which have access to low cost New Mexico gas supplies?

A. Yes, but by no more than what is considered economically prudent as determined by market clearing prices. It is only logical that any pipeline would expand its service to the lowest cost and most abundant gas producers. Any other choice would reduce the economic viability of the pipeline. By increasing productive pipeline capacity, the prior El Paso, Transwestern, Kern and the 1993 Expansions have, each in their own turn, increased slack capacity and forced other sellers of gas into the California market to become more price competitive.

Q. Does your analysis support any additional conclusions about the impact of the 1993 Expansion on California natural gas prices?

A. The only logical conclusion that can be drawn from my analysis is that increasing PGT's pipeline capacity into California has measurably lowered the price paid for gas by California gas

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[11/] "Natural Gas Market Assessment: Natural Gas Supply Western Canada," National Energy Board, November 1993. ISBN 0-662-21203-7.

consumers. This price lowering effect is on the order of $0.169 for each MMBtu of gas delivered to the California border, producing annual direct savings to California consumers of about $350 million. However, this benefit is proportionately no more or less than has resulted from the other recent California expansion projects I have included in my analysis. It is also likely that the slack pipeline capacity introduced by the 1993 Expansion has reduced seasonal price volatility. This observation is based on examination of recent years' price data, especially noting that, for February and March 1994, California consumers were spared the cold weather induced price increases experienced by other parts of the country.

Q. Have natural gas price benefits occurred in the Pacific Northwest, as well as in California, as a result of the 1993 Expansion?

A. I know of no reason why pipeline capacity which promotes gas-on-gas competition at the California Border should not also promote gas-on-gas competition in the Pacific Northwest. However, the structure of the Pacific Northwest market prevents me from developing for it the same kind of single, concise econometric equation estimating this effect, as I did for the California market. Unlike the California market, which is a large terminal destination, much of the Pacific Northwest pipeline capacity simply traverses the region and is intended for other destinations, although in many cases this capacity could serve the Northwest as well. To illustrate this, Idaho has nearly 4,000 MMcf/d of wintertime capacity, yet has only 200 MMcf/d of demand. Thus, it would be more difficult to measure the slack capacity and/or to estimate the price impacts under such circumstances. This same concern regarding traversing vs. local destination capacity applies to the other states in the Northwest region as well. Although I believe there are benefits, this is why I have not quantified the price changes in the Northwest.

IV. INDIRECT ECONOMIC BENEFITS TO THE CALIFORNIA ECONOMY

Q. What is the nature of the indirect benefits that have resulted from the 1993 Expansion?

A. The direct gas-on gas competitive price benefits of the 1993 Expansion to California=s natural gas consumers in turn provide a stimulus to the statewide economy. When a region=s income is increased (for any reason, including, in this case, an increase in income due to a price decrease in an essential imported product to the region) there will be a positive stimulus or Amultiplier effect≅ to that region=s economy. It makes no difference whether the income inflow to the region is increased or the income outflow is decreased. In either case, the economic stimulus will have two distinct components: a direct component which is caused by added spending by the consumers who received the added income, and an indirect component which is caused by the spending of businesses and their employees whose sales are increased. The U.S. Department of Commerce measures these multiplier effects and periodically publishes values for multipliers for the different sectors of the economy state-by-state.

Q. How widely recognized is your view that a decline in consumer prices will improve a region's economy?

A. For many years it has been the standard policy of the United States Departments of Commerce and Energy that an economic impact will result from a regional income transfer and that these economic impacts or multipliers should be explicitly considered in any policy analysis.

Q. Are there any limitations or caveats in using these multipliers?

A. Yes. The multiplier methodology assumes that (1) lower prices in a region lead to lower dollar imports of product from outside the region and (2) that the added income from the lower prices is spent in ways proportional to the average expenditures of consumers and industries in the region. The total multiplier impact would be reduced (relative to the average multiplier impact measured by the U.S. Department of Commerce) if, for example, lower gas prices caused less California gas to be produced, more gas consumed or consumers saved (rather than spent) their price savings from natural gas purchases.

Q. Have you calculated the indirect economic impacts of the 1993 Expansion in California, using your estimate of the direct consumer benefits as a starting point?

A. Yes, I have. I calculated the gas price benefit to California consumers of the 1993 Expansion as $354 million per year in 1994. I then derived an overall economic multiplier for

California by taking the latest U.S. Department of Commerce sector multipliers for the State and weighting them by 1991 California sector output.[12/] This is shown in Exhibit SCE__(AVH-16). I used the resulting multiplier of 2.156 to calculate the total direct and indirect economic impact created by these lower consumer prices. This results in an indirect benefit of an additional $409 million per year in 1994 (2.156 x $354 million per year minus $354 million per year direct benefits).

Q. How do you calculate the benefit stream?

A. To compute benefits over time, I calculated the direct and indirect benefits in relation to the gas consumption forecast in the 1993 California Gas Report. Exhibit SCE___(AVH-17) shows the results of this calculation through the year 2013. It also shows the net present value of these benefits calculated at a 5% and a 10% per year discount rate.

Q. What are the total economic benefits?

A. The levelized annual direct and indirect economic benefits through the year 2013 are about $951 million per year, as shown in Table AVH-2, having a net present value of $8.8 billion at a 10 percent discount rate.

Q. Are there any other assumptions that would have a major effect on the outcome of your indirect economic impact analysis?

A. My calculation of direct gas-on-gas competition benefits is based on the observed price responses to pipeline expansions shown by recent historical data. I assume that the California gas industry will not undergo major structural changes in the future which would substantially alter the direct benefits of the 1993 Expansion per unit of gas purchased at the California border from that which I observed. The other assumptions that enter into my forecast of future benefits are the ones described above that relate to forecasting California natural gas demand growth, the

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[12/] 1991 is the latest year for which data is available on California output by sector (U.S.D.O.C., Bureau of Economic Analysis, Survey of Current Business, August 1994). The U.S. Department of Commerce publishes state sector multipliers in its Regional Impact Multiplier System Manual. See RIMS-II Manual, May 1992, US Government Printing Office, IBSN 0-16-037944-X.

calculation of an overall economic multiplier for California, and the choice of a discount rate for the net present value calculation. Changing these variables within accepted ranges would not have a major impact on my overall conclusion of significant future direct and indirect benefits from the 1993 Expansion.

V. ENVIRONMENTAL BENEFITS

Q. Will the PGT expansion provide substantial environmental benefits?

A. Yes. The expansion adds capability to import more natural gas into California and the Pacific Northwest. Without an expansion of the interstate pipeline capacity serving California after 1992, such as the 1993 PGT Expansion, California's available interstate gas delivery capability would become inadequate to meet forecasted demand, requiring the substitution of other, less clean fuels after 1997.

Q. To what extent would projected shortages of gas occur in California without the 1993 PGT Expansion and in the absence of any new interstate pipeline capacity after 1992?

A. Based on the demand growth projected in the *1993 California Gas Report* and on total in-state gas production projected in the California Energy Commission's *1993 Natural Gas Market Outlook*, I have estimated a 130 MMcf/d shortfall of supply below projected consumption levels for Northern California by year 2000, growing to a 1045 MMcf/d shortfall statewide by 2010.

Q. How is this shortfall distributed among various consuming sectors?

A. By studying historical load factors in California, I note that on an annual basis even "full" pipelines generally operate at an annual load factor below 90% of capacity. This is caused by swings in seasonal demand, coupled with limited storage facilities. For California I have used a 90% annual load factor to represent a practical limit on the utilization of interstate pipelines to meet forecasted demand without encountering problems that would discourage future commitments to gas versus other energy sources.[13/]

[13/] Between January 1990 and October 1993, the PGT pipeline operated at between 85 and 89 percent average annual load factor at Kingsgate and slightly higher if measured at Malin.

I then characterized the growth in natural gas usage in different consuming sectors separately for Northern and Southern California. My allocation of existing interstate supplies to Northern and Southern California is based the *1993 California Gas Report*, and I projected in-state gas production using the California Energy Commission's *1993 Natural Gas Market Outlook*. I then allocated the resulting projected shortfall of supply relative to forecasted demand among the different gas consuming sectors in Northern and Southern California in proportion to each different sector's projected demand growth forward from 1993 to the particular year of estimation. Growth was based on the added consumption after 1993 projected in the *1993 California Gas Report*. The estimated contribution of the 1993 Expansion to avoiding a shortfall was assumed to be limited by a 90 percent annual load factor. The distribution of this projected shortfall among various consuming sectors is given in Exhibit SCE___(AVH-18). Note that the projected shortfall starts earlier in Northern California, where the 1993 Expansion capacity represents a larger share of overall gas supply than in Southern California.

Q. How did you quantify the degraded environmental quality that would result from higher emissions, if natural gas pipeline capacity were to be limited to pre-1993 levels?

A. After projecting the amount of gas shortfall that would be avoided by the 1993 Expansion, I calculated shortfall-related increases in the use of substitute fuels and their associated emissions. This analysis was performed for several major end-use categories using available information on historical and projected fuel use patterns, end-use efficiencies and fuel combustion emission factors. The most consequential substitute fuels included gasoline in light duty vehicles, propane, distillate and wood for heating homes, and oil for electricity generation and industrial applications. Some kinds of emission increases that would result from fuel substitution for natural gas were not quantified, such as industrial bypass and commercial gas uses. Also omitted were fuel cycle emissions, such as emissions from petroleum transport and refining.

More broadly, a gas shortfall would restrict California's presently anticipated reliance on new, efficient in-state gas-fired power plants. This circumstance would lead directly to more expensive electricity, and indirectly to environmental consequences that would be dependent on the sources of alternative in-state and out-of-state electric generation, and on altered electricity uses, including the reduced electrification of fuel combustion applications.

Q. How did you derive the value of avoided emissions?

A. The value of the "avoided environmental damage" from avoiding the emissions from substitute fuels can be measured in $/ton of avoided emissions (i.e., the emissions difference between burning substitute fuels versus those from burning natural gas). The California Energy Commission (CEC) has evaluated $/ton values based on environmental damages associated with the emission of various pollutants (*Docket No. 93-ER-94, Subcommittee Order on Air Quality Assumptions, 9/1/94*). As derived by the CEC, these values apply directly when the emissions come from the specific power plant locations considered in each of seven regions in the state. However, despite their inherent limitations, these damage values also provide the most relevant means of valuing damages from different emission sources located in the various regions of the state and are preferable to using more generic damage values developed elsewhere. As noted by the CEC, the issue of how to apportion ozone-related damages between NO_x and ROG (reactive organic gases) emissions has been difficult to resolve and depends on location-specific circumstances. One of several alternatives developed by the CEC apportions ozone damages 50:50 between NO_x and ROG, which is the approach I have used here.

I have aggregated some of the CEC's $/ton emission damage values for seven regions of the state in order to cover the entire state, which I have broken into five overall regions as shown in Exhibit SCE___(AVH-19). In this aggregation, the damage values assigned to Northern California other than the Bay Area represent the unweighted average of the CEC's values for the North Coast and the North Central Coast air basins, and the damage values for Southern California, other than the South Coast Air Basin or San Diego County, represent the unweighted average of the CEC's values for the Southeast Desert and South Central Coast air basins. As described in the footnote to Exhibit SCE___(AVH-19), alternative NO_x damage values were used for electric generating units in the South Coast Air Basin, since these units would likely be the major NO_x sources subject to the RECLAIM emission credit trading program.

Q. Have you evaluated environmental benefits other than the reduction in air pollutants?

A. No, I have not. The various avoided damage values summarized above are for air emissions; they exclude water pollution, habitat disruption and land use damages, which are likely to be considerably lower in general, but can be substantial for particular situations, such as for hydroelectric projects.

Q. How did you go about estimating the benefits of reduced air emissions in the various regions?

A. For each end-use sector and pollutant, I estimated the differences in air emissions, "with" versus "without" the 1993 Expansion. My calculations were based on the gas shortfalls avoided by the Expansion capacity to California and the substitute fuels that would be avoided by using gas.

I applied $/ton values to residential emissions estimated for each subregion (e.g., Bay Area versus "other" Northern California). For emissions from other sectors I applied $/ton values on a regional basis, separately for Northern and Southern California. These "Northern" and "Southern" $/ton emission damage values were calculated as weighted averages over the different subregions, with the weights being 1991 populations given in the California Air Resources Board's *Emission Inventory 1991* (January 1994, Table I-1).

Q.What is the valuation of future air quality benefits due to the 1993 PGT Expansion?

A. The resulting tons per year of emission benefits from the 1993 Expansion are shown in Exhibit SCE___(AVH-20) for each pollutant. The dollar values of the corresponding environmental benefits from these avoided environmental damages are shown in Exhibit

SCE___(AVH-21) for years 2000, 2005, and 2010. I interpolated to estimate the dollar benefits in the intervening years, in order to give year by year aggregate benefits and to calculate their net present value (Exhibit SCE___(AVH-17)), as well as the levelized value of the benefits. (See Table AVH-2).

Most of the air quality benefits are in the South Coast Air Basin and the Bay Area, due to these regions' large projected demand for natural gas and their high population densities that lead to high $/ton emission valuations.

VI. COMMENSURATE BENEFITS TO PRE-EXPANSION CUSTOMERS AND EXAMPLES OF MARKET INEQUITIES FROM VINTAGE RATES ON PGT

Q. Have you evaluated the 1993 Expansion's impact on pre-expansion customers within the context of FERC's commensurate benefits test?

A. I have strictly applied the commensurate benefits test to the pre-expansion California customer rate class, which obtains service under rate schedule FTS-1 and to PITCO which transports natural gas to California under rate schedule FTS-1 (T-2). The commensurate benefits for FTS-1 and PITCO customers cover 96% of all pre-expansion customers [when measured on an as-filed revenue requirements basisXsee Exhibit SCE_(BWW-3)].

Q. Please discuss the results of your calculations of commensurate benefits for FTS-1 and PITCO customers.

A. For these two pre-existing customer classes, I have calculated the difference between equalized and incremental (vintage) rates based on the average load factor assumption used in PGT's rate filing for pre-expansion customers in this case. As shown in Exhibit SCE__(AVH-22), equalized rates would result in FTS-1 customers incurring added costs of 11.6 cents more per MMBtu for gas transportation than they would pay under vintage rates in the first year. Exhibit SCE_(AVH-23) shows that the increased transportation charge to PITCO would be 3.7 cents per MMBtu for gas shipped under rolled-in rates, of which 2.8 cents would be due to the effects of the Gas Supply Restructuring costs.

However, on the benefit side, FTS-1 customers are receiving a total of 19.6 cents in direct benefits per MMBtu of gas shipped. These direct benefits are in the form of price reductions at the California border from increased gas-on-gas competition, fuel savings on PGT, and increased service reliability and flexibility. For PITCO, these direct benefits total 18.5 cents per MMBtu. Thus, on a direct basis, the net benefits of the 1993 Expansion for FTS-1 and PITCO customers outweigh the added costs of rolled-in rate treatment by 8.0 cents per MMBtu and 14.8 cents per MMBtu, respectively.

Q. Are there indirect benefits that should be included in this calculation as well?

A. Yes. As I describe in other sections of my testimony, there are economic multiplier and environmental benefits associated with the lower cost and greater use of natural gas in California that FTS-1 and PITCO customers receive from the 1993 Expansion. These added benefits are listed as indirect benefits in Exhibits SCE___(AVH-22) and SCE___(AVH-23). When these indirect benefits are accounted for, the first year total benefits of the 1993 Expansion exceed the added cost of rolled-in rate treatment to FTS-1 and PITCO customers by 30.6 cents and 36.1 cents, respectively. By either of these commensurate benefit measures, the immediate roll-in of 1993 Expansion costs to FTS-1 and PITCO customers is more than justified. Given the benefits received, FTS-1 and PITCO customers should pay fully rolled-in rates.

Q. In theory, should the per-MMBtu commensurate benefits calculation you have performed be applied to all volumes now shipped under the FTS-1 and PITCO rate schedules?

A. No, it should not. But even if it were applied to all volumes, in an extreme interpretation of the commensurate benefits test, my calculations show that the benefits to all customers using FTS-1 and PITCO rates far outweigh the added cost of the new rolled-in rates, including 1993 Expansion costs for these customers.

Q. Please explain why the commensurate benefit test is not appropriate for all the pre-existing volumes. Are all volumes shipped under the FTS-1 and PITCO tariffs destined for end-use customers who were customers of the pre-expansion PGT system?

A. No, they are not. If adopted by the FERC in this case, the commensurate benefits standard should not be applied to all FTS-1 and PITCO volumes, because many end-users who benefit from FTS-1 and PITCO vintage rates are new California end-use customers and/or are indistinguishable from end-users whose gas is transported on the 1993 Expansion. Their only distinction is that they obtained rights to FTS-1 capacity through capacity release.

Q. How did this occur?

A. PG&E and Pacific Enterprises (the holding company parent of SoCalGas) are the original holders of FTS-1 and PITCO capacity, respectively. These local distribution companies historically used their capacity to serve both core and non-core customers within their service territories. In the post-Order No. 636 environment, both utilities have and are planning to release substantial amounts of their pre-existing firm capacity that is not now required for core needs. In the case of PG&E, which was ordered by the CPUC to release firm capacity, the released FTS-1 capacity initially amounts to 405 MMcf/d, a substantial portion of the total 1055 MMcfd FTS-1 capacity at Malin. Parties acquiring this released capacity may, or may not, have even existed, let alone used or benefitted from FTS-1 or PITCO capacity prior to the 1993 Expansion in-service date.

Q. Can you provide an example of the kind of inequity that vintage rate treatment for the 1993 Expansion has caused?

A. Yes, I can. Crockett Cogeneration is a new 260 MW combined cycle power facility located in PG&E's service territory. It is not yet in operation but is scheduled to be placed in service in late-1995. As soon as capacity brokering was implemented in California for the FTS-1 volumes, Crockett acquired rights to 46,575 Mcf/d of FTS-1 capacity for a 12-year period. According to press accounts, its natural gas supplier is Amoco. Amoco also acquired 46,575 Mcf/d of FTS-1 capacity rights from January 1, 1994 until October 31, 1995 (see PGT's testimony, Volume IV, for capacity release information).

Amoco is one of the largest natural gas producers in North America. It holds no 1993 1993 Expansion capacity, having previously backed the Altamont Pipeline Project. Presumably, Amoco will use its released FTS-1 capacity to transport Canadian gas to new California non-core customers and then to Crockett Cogeneration once the plant begins operation.

Depending on how the Crockett/Amoco gas contract price is structured, either Amoco or Crockett Cogeneration (or perhaps both) would reap the benefit of the lower-priced FTS-1 transportation rights that Crockett has acquired. To the extent that Amoco does, it will benefit by paying less for the same service than competing producers who committed to capacity on the 1993 Expansion (even though Amoco backed an alternative pipeline venture instead). To the extent Crockett Cogeneration benefits, it will obtain a cost advantage in a deregulated power market relative to companies like Southern California Edison, which backed the 1993 Expansion and are now paying higher vintage rates for identical service. In neither case does it seem equitable that these new parties, who made no financial commitment to either PGT's pre-existing or Expansion pipeline, should now receive benefits under vintage rates that other parties who supported the 1993 Expansion are denied.

Q. Do the inequities flow the other way as wellXthat is, do any parties who once transported their natural gas supplies using FTS-1 service now pay higher vintage rates for the same service on the 1993 Expansion?

A. Yes, they do. Prior to the California Public Utility Commission's gas industry restructuring of August 1991, most of PG&E's non-core customers purchased bundled commodity and transportation service from PG&E. A large part of the portfolio of natural gas that these non-core customers bought was transported to California on PGT using FTS-1 service. Then, in August of 1991, a group of these non-core customers, representing a daily volume of about 250 MMcf/d, chose to purchase their natural gas in Canada and transport it to California under the Customer Identified Gas (CIG) program. This CPUC-sanctioned program allowed non-core end-users in PG&E service territory to contract directly with producers and marketers in Canada for purchase of natural gas, which then flowed to California under PG&E's FTS-1 service on PGT.

The Customer Identified Gas program ended with the implementation of Order No. 636 and the in-service date of the 1993 Expansion on November 1, 1993. Some CIG program participants continue to benefit from FTS-1 service via capacity release, but others do not. The same is true of PG&E's non-core customer group generally. Benefiting or not benefiting from FTS-1 service is a function of luck and timing for PG&E non-core customers. The ability for some PG&E non-core users who were pre-expansion customers to obtain FTS-1 service, but not for others, is inequitable while 1993 Expansion customers are paying higher vintage rates. All California non-core users of PGT should pay the same price for the same service, because none of them were holders of firm capacity on PGT's pre-expansion pipeline.

Q. Are there any other examples of new customers receiving preferential treatment under vintage rates, or pre-existing customers who had been on the old FTS-1 rates but will now be disadvantaged?

A. The major beneficiary of vintage rates is PG&E's core customer class. Anyone who moves into the PG&E service area (about 25% over the 1980-1990 census period) will receive preferential treatment from such vintage rates. Correspondingly, most local firms buying Canadian gas from non-PG&E sources will lose that preference.

In the future, when electricity markets are more competitive, Southern California Edison, using the 1993 Expansion facilities to deliver gas under vintage rates to its electric generation plants, could be paying more than others using the original PGT facilities, even though both receive the same service.

Q. What conclusion do you reach from your analysis of the commensurate benefits to pre-existing customers?

A. My calculations show that the overall benefits to California customers currently using

FTS-1 and PITCO firm capacity rights far outweigh the added cost of rolled-in rates. Since the benefits to these customers are more than commensurate with the cost to them of rolled-in rates, rolled-in (equalized) rate treatment is appropriate and fair in this situation. The equity of rolled-in rate treatment for the 1993 Expansion is further compounded by the fact that many of the original users of the pre-expansion system (non-core end-users in the PG&E service territory) are indistinguishable from 1993 Expansion users. There is no logical reason to differentiate among these users, each of whom should be paying equal rates for equal service.

VII. ECONOMIC PERSPECTIVE ON THE SIZE OF THE 1993 EXPANSION

Q. Are there other considerations that are relevant to the commensurate benefit tests outlined in Exhibits SCE_(AVH-22) and SCE_(AVH-23)?

A. Yes, there is another important factor: the impact of the current expansion on the cost of future expansions. If this impact is large, then any vintage transportation rates, and even the rolled-in rates (which I believe are most appropriate in this case) should be modified to reflect a more equitable distribution of capital charges over time. My analysis shows that wide differences in possible vintage rates can result from adding different increments of capacity. Such a rate treatment for successive expansions is not only inequitable but also sends confusing market signals to capacity users.

Q. Why do you expect that the current expansion would have an impact upon the costs of future expansions?

A. PGT's testimony states that the next stage of expansion beyond the 1993 level will require only added compressors, rather than added looping of pipe. "Compressor-only" expansions are considerably lower in capital cost and are, therefore, cheaper than expansions requiring looping or new pipe in the ground. (It should be noted, however, that increased fuel use can offset the low capital costs.) Thus, the relative costs of added capacity will vary greatly, depending on the status of a pipeline with respect to whether its next incremental capacity addition involves only compression or a combination of new pipe, looping and compression.

In fact, PGT could have decided to add only compression to its pre-1993 capacity, with no added looping. However, this would not have provided sufficient added capacity for all those customers who wanted access to the Canadian market. Thus, PGT chose to complete the looping of its pre-Expansion facilities, leaving the door open for further, compression-only expansion.

It is a common and prudent business practice that when a firm is making one expansion, it leaves the door open for future expansions. When a major capital project is undertaken, it is only good sense that appropriate steps are also taken to facilitate (or, at least, not to hinder) future capital investments. Such steps might include, for instance, the identification and purchase of right-of-ways, equipment and structures that are sized to accommodate additional expansion.

Q. Has any analysis been performed that might quantify the economic impact of the 1993 Expansion upon future expansions?

A. Yes. Southern California Edison's (SCE's) pipeline engineering consultant, Stoner Associates of Houston, Texas, has estimated the costs of different-sized expansions to the pre-expansion facilities that might have been constructed in lieu of the 1993 Expansion. Using this data, I sought to determine the relative economic costs of the capacity PGT chose to build in relation to each alternative (both smaller and larger) expansion that might have been selected.

Q. What were the steps in this analysis?

A. Stoner Associates developed nine different technically feasible expansion options which would have increased throughput capacity at Malin in various amounts ranging from 100 to 1009 MMcf/d.

Stoner Associates also developed cost and operating parameters for each of these alternatives. Given this data, SCE's rates consultant, Betsy Waller, computed the approximate vintage versus equalized rates that each of these alternative options would have required. I reviewed these to see if specific conclusions could be drawn regarding the economics of PGT's chosen plan relative to the alternatives. I determined whether or not vintage rates for the 1993 Expansion would send a consistent "market signal" to capacity users of different vintages.

Q. Would you summarize the results of this phased-expansion analysis?

A. Exhibit SCE__(AVH-24) (1st Year Vintage vs. Rolled-in Rates) shows both equalized and vintage rates for several increments of capacity that PGT might have added to the pre-existing system, based on costs estimated by Stoner Associates and rates developed by SCE witness Waller. At the low end, PGT could have added 100 MMcf/d of capacity at a vintage transport rate of 36 cents per MMBtu, including added fuel consumption. This addition would not have met the expansion needs of all PGT customers. The next three potential capacity increases above the pre-Expansion capacity level (110, 209 and 293 MMcf/d) would have required new pipeline looping and, by themselves, would have led to considerably increased costs and rates. The next two larger capacity additions after that, 674 and 901 MMcf/d, are more cost-effective per MMcf of added capacity, measured by rates calculated on both a vintage and a marginal basis. In this size range, the marginal cost of adding capacity is less than either the resulting equalized (rolled-in) or vintage rates.

Q. What do you mean by rates calculated on a marginal basis?

A. By "marginal" I mean the rate that would apply to the next increment of capacity at each successive level of capacity, rather than the vintage rate that is based on the costs of an entire expansion relative to the pre-Expansion level of capacity.[14/] Exhibit SCE__(AVH-25) shows a marginal cost-rate for each successive increment of added capacity relative to the prior increment. This rate indicates the relative marginal costs of expansion at each potential level of capacity expansion analyzed by Stoner Associates. The wide differences in this marginal rate, as well as the variations in the vintage rates shown in Exhibit SCE__(AVH-24), demonstrate that customers would pay widely different rates depending on their vintage, the size of the addition, and whether or not the added capacity required looping. If true vintage rates were applied, extremely different market signals would result for successive PGT capacity additions, despite the fact that all customers receive the same service.

Q. Please explain how vintage rates would lead to fluctuating and considerably different rates for the same service.

A. Unless PGT's rates reasonably reflect the long-run marginal costs to society of an

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14/ The marginal cost equals the change in total cost that results when total output changes by a small amount. See Samuelson, Paul and William Nordhaus, *Economics*, (1992), McGraw-Hill, Fourteenth Edition, p. 343.

expansion, there could be either an over or under investment in pipeline expansion facilities and more or less gas consumption relative to other fuels. If PGT's rates were based on either "true" marginal costs or on vintage rates, corresponding to each of the smaller increments of capacity I've examined, both the vintage and marginal rates would fluctuate widely based on the stage of PGT's expansion cycle. Such wide differences in rates and in market signals, solely due to a customer's vintage in signing up for otherwise identical firm transportation service, would be economically inefficient and inequitable.

Q. Was it economically desirable for PGT to choose to build the size expansion it selected?

A. Yes. As long PGT's market demand demonstrates access to a competitive supply basin, it makes economic sense to expand up to a level of capacity where economies of scale are achieved. Exhibits SCE__(AVH-24) and SCE__(AVH-25) show that additional increments of capacity above PGT's current capacity would still be in the range in which economies of scale apply. As I have also demonstrated, the marginal increase in the slack capacity that results from an added increment of capacity at today's "compressor-only" stage in PGT's expansion cycle would increase gas-on-gas competition, providing even further gas price benefits to all consumers.

It should be noted from Exhibits SCE__(AVH-24) and SCE__(AVH-25) that, for several additions beyond the 1993 PGT Expansion, added costs would be well below the estimated rolled-in rates of about $0.33 per MMcf, which are, in turn, below vintage rates of about $0.40. Thus, the rate which best approximates today's marginal cost of capacity expansion and sends a more correct market signal is a rolled-in rate, not a vintage rate.

Q. Do recent data support the concept of further expansion?

A. Yes, they do. Since the 1993 Expansion began operation in November of 1993, the average daily Expansion throughput has been about 534 MMcf/d. This represents a load factor of about 71% when measured against PGT's stated capacity of 755 MMcf/d for the 1993 Expansion. In recent months, PGT's overall load factor has exceeded 90 percent.

Q. What do you conclude from your marginal analysis of alternative expansion options that were available to PGT?

A. I conclude that PGT chose to expand to a level that was within the cost-effective range, exhibiting desirable economies of scale. Further, PGT is now at a stage of its expansion cycle where capacity can be added at a low marginal cost (below equalized rates). The equitable allocation of those costs and benefits over the expansion cycle should be a strong factor in deciding in favor of equalized (rolled-in) rates instead of vintage, incremental rates in this case. Importantly, all customers use the fully-integrated facilities of PGT and receive the same service. Thus, continuing to impose vintage rates is both economically inefficient and inequitable for PGT's customers.

Q. What overall conclusions do you reach from your analysis of the benefits and costs of the 1993 Expansion?

A. The 1993 Expansion will provide substantial benefits to California consumers that far exceed the costs of the project. These benefits have been demonstrated during 1994 and will continue over the expected life of the 1993 Expansion facilities. For the reasons given above, equalized, rolled-in rates would be economically more efficient and more equitable than vintage rates.

Q. Does this conclude your testimony?

A. Yes.

Exhibit SCE__(AVH-17)

Benefits of the 1993 PGT Pipeline Expansion to California

Year	Gas-on-Gas Competition		Pipeline Efficiency		Environmental	Total
	Direct: Lower Prices	Indirect: Economic Multipliers	Direct	Indirect	Air Quality	
	--------------------(Million Dollars)--------------------					
1994	354	409	10	11		783
1995	363	420	10	11		803
1996	372	429	10	11		822
1997	380	439	10	11		840
1998	389	449	10	11	6	864
1999	397	459	10	11	11	889
2000	406	469	10	11	17	913
2001	412	477	10	11	29	938
2002	419	484	10	11	40	964
2003	425	491	10	11	52	989
2004	432	499	10	11	72	1,023
2005	438	506	10	11	92	1,056
2006	444	513	10	11	106	1,083
2007	449	519	10	11	121	1,110
2008	455	526	10	11	136	1,137
2009	461	532	10	11	151	1,164
2010	466	539	10	11	166	1,191
2011	472	545	10	11	172	1,210
2012	478	552	10	11	179	1,230
2013	484	559	10	11	186	1,250
Discount Rate	--------------------Net Present Value (Million Dollars)--------------------					
5%	5,416	6,261	125	145	891	12,716
10%	3,786	4,377	90	104	546	8,766

Exhibit SCE_(AVH-18)

Distribution of Gas Shortfall among Consuming Sectors in the Absence of the PGT Expansion (MMcf/d)

Sector	Northern California			Southern California	
	2000	2005	2010	2005	2010
Residential	16.7	64.2	90.1	12.7	33.8
Natural gas vehicles	15.7	41.5	34.4	26.4	46.1
Other Commercial	5.9	21.4	26.0	6.1	17.7
Industrial	19.6	58.5	70.1	0	0
Electric Generation[1]	65.6	137.4	132.6	53.1	123.7
Bypass	2.4	0	0	10.9	40.4
Other (wholesales, company use)	3.6	9.5	11.3	20.5	53.2
Total	129.6	332.6	364.5	129.6	315.0

[1] Electric utility plus non-EOR (enhanced oil recovery) cogeneration.

Exhibit SCE_(AVH-19)

California Emission Damage Values
Based on Values Developed by the California Energy Commission [1]
(Nominal Dollars/Ton)

	Year 2000					Year 2005					Year 2010				
	South Coast	San Diego	Other South	San Fran.	Other North	South Coast	San Diego	Other South	San Fran.	Other Northern	South Coast	San Diego	Other South	San Fran.	Other North
NO_x	27576	3648	2133	9187	1061	46177	5293	2991	11964	1694	57811	6872	4097	15754	1947
ROG	28981	11263	1289	9742	44	37899	27133	352	8648	5536	36018	2360	756	11822	888
SO_2	438	438	438	438	438	698	698	698	698	698	1102	1102	1102	1102	1102
CO	8	3	0.5	4	0	13	3	1	5	0	18	6	1	6	0
PM10	74852	27072	4768	26644	5690	94875	30733	6204	32696	7194	128361	37731	9121	43653	9661
CO_2	11.7	11.7	11.7	11.7	11.7	14.5	14.5	14.5	14.5	14.5	17.5	17.5	17.5	17.5	17.5

1 As noted by the CEC, the allocation of ozone related damages between NO_x and ROG (reactive organic gases) depends on location-specific conditions. This table apportions ozone damage 50:50 between NO_x and ROG. For the South Coast Air Basin alternative NO_x damage values listed below were used by the CEC for electric generation sources, since these would likely be major NO_x sources included in the RECLAIM emission credit trading program. The estimated $/ton NO_x prices for the RECLAIM program reflect a gradual reduction in the level of emissions allowed and are $26,111/ton for year 2000, $43,791/ton for year 2005, and $55,080/ton for year 2010. These alternate values were used for electric generation only. The number in the table above was used for other source categories.

Exhibit SCE_(AVH-20)

California Emission Reductions
in the Years 2000, 2005, 2010 Due to the 1993 Expansion
(tons reduced)

Pollutant	Year 2000			Year 2005			Year 2010		
	SoCal	NoCal	Total	SoCal	NoCal	Total	SoCal	NoCal	Total
ROG		469	469	308	1,583	1,891	552	1,951	2,503
NO_x		240	240	74	723	797	156	888	1,044
CO		4,653	4,653	1,863	16,645	18,508	3,355	21,772	25,127
SO_2		901	901	267	2,319	2,586	592	2,556	3,148
CO_2		322,626	322,626	349,578	891,213	1,240,790	637,169	897,553	1,534,722
PM10		576	576	47	2,146	2,193	109	2,971	3,080

* Includes Natural Gas Vehicles, Residential Heating, Industrial and Electric Power Plant Fuels Substituting for Natural Gas in the absence of the PGT Expansion.

Exhibit SCE_(AVH-21)

Benefits from Emission Reductions in California in the Years 2000, 2005, 2010 Due to the 1993 Expansion* (thousand dollars)

Pollutant	Year 2000			Year 2005			Year 2010		
	SoCal	NoCal	Total	SoCal	NoCal	Total	SoCal	NoCal	Total
ROG		2,976	2,976	9,683	12,075	21,758	14,593	16,637	31,229
NO_x		1,418	1,418	2,690	5,878	8,567	7,100	9,660	16,760
CO		13	13	18	59	77	46	95	141
SO_2		395	395	187	1,619	1,805	653	2,817	3,469
CO_2		3,784	3,784	5,053	12,882	17,935	11,122	15,666	26,788
PM10		12,142	12,142	3,280	56,088	59,367	10,132	104,039	114,171
Total All Pollutants except CO_2		16,945	16,945	15,858	75,718	91,576	32,522	133,247	165,770

* Includes Natural Gas Vehicles, Residential Heating, Industrial and Electric Power Plant Fuels Substituting for Natural Gas in the absence of the PGT Expansion.

Exhibit SCE_(AVH-22)

First Year Commensurate Benefits Test for Pre-Expansion FTS-1 Customers in California

	Rolled-in Rates ($/MMBtu)	Vintage Rates ($/MMBtu)	Difference ($/MMBtu)
PGT Demand Rate @ 79% LF*	$0.353	$0.177	($0.176)
PGT Commodity Rate	$0.011	$0.019	$0.008
Gas Supply Restructuring Surcharge**	$0.054	$0.106	$0.052
SUBTOTAL DIRECT PGT COSTS	$0.312	$0.196	($0.116)
CA Border Pri			$0.169
Fuel Benefits @ $1.61/MMBtu***			$0.019
Increased Service Reliability and Flexibility****			$0.008
SUBTOTAL DIRECT BENEFITS			$0.196
Regional Multiplier Benefits			$0.226
Environmental Benefits*****			NA
SUBTOTAL INDIRECT BENEFITS			**$0.226**
TOTAL NET BENEFITS FROM THE 1993 EXPANSION			$0.306

* Based on a 100% load factor rolled-in demand charge rate of $0.279/MMBtu and a 100% LF vintage demand rate of $0.14/MMBtu.

** Based on estimates contained in Howard T. Ash's testimony, Exhibit HTA-2, divided by the base period throughputs shown in Exhibit HTA-4.

*** Assuming fuel savings of 0.0019 percent per mile, as reported in Howard T. Ash's testimony, Page 23, and assuming a 1995 natural gas price at Kingsgate, which is the mid-range of the price forecast made by Dobson Resource Management Ltd., as reported in Ash's testimony, Exhibit HTA-4 divided by the base period throughput of 447,926,276 MMBtu, also shown in Ash's Exhibit HTA-4.

**** Based on the mid-range of PGT's estimate for these benefits, as provided in Howard T. Ash's testimony, Exhibit HTA-3 divided by the base period throughput in Exhibit HTA-4.

***** Environmental benefits attributable to the 1993 Expansion begin in 1998.

Exhibit SCE__(AVH-23)

First Year Commensurate Benefits
Test for PITCO Service [FTS-1 (T-2)]

	Rolled-in Rates ($/MMBtu)	Vintage Rates ($/MMBtu)	Difference ($/MMBtu)
PGT Demand Rate @ 78% LF*	$0.162	$0.151	($0.011)
PGT Commodity Rate	$0.005	$0.007	$0.002
Gas Supply Restructuring Surcharge**	0.028	--	(0.028)
SUBTOTAL DIRECT PGT COSTS	$0.195	$0.158	($0.037)
CA Border Price Benefit			$0.169
Fuel Benefits @ $1.61/MMBtu***			$0.008
Increased Service Reliability and Flexibility****			$0.008
SUBTOTAL DIRECT BENEFITS			$0.185
Regional Multiplier Benefits			$0.213
Environmental Benefits*****			NA
SUBTOTAL INDIRECT BENEFITS			$0.213
TOTAL NET BENEFITS FROM THE 1993 EXPANSION			$0.361

* Based on a 100% LF rolled-in demand charge of $0.126/MMBtu and a 100% LF vintage demand rate of $0.118/MMBtu.

** Based on estimates contained in Howard T. Ash's testimony, Exhibit HTA-2, divided by the base period throughputs shown in Exhibit HTA-4.

*** Assuming fuel savings of 0.0019 percent per mile, as reported in Howard T. Ash's testimony, Page 23, and assuming a 1995 natural gas price at Kingsgate, which is the mid-range of the price forecast made by Dobson Resource Management Ltd., as reported in Ash's testimony, Exhibit HTA-4 divided by the base period throughput of 447,926,276 MMBtu, also shown in Ash's Exhibit HTA-4.

**** Based on the mid-range of PGT's estimate for these benefits, as provided in Howard T. Ash's testimony, Exhibit HTA-3.

***** Environmental benefits attributable to the 1993 PGT Expansion begin in 1998.