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BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION
DOCKET NO. R-00016378

IN THE MATTER OF THE FILING OF
PHILADELPHIA GAS WORKS
CONCERNING ITS
2001-2002 GAS COST RATE

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DIRECT TESTIMONY OF
RICHARD W. LELASH
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE

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FOLDER

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# PHILADELPHIA GAS WORKS
# GCR FISCAL YEAR 2001-2002
# TESTIMONY OF RICHARD W. LELASH

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## I. STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Richard W. LeLash and my business address is 18 Seventy Acre Road, Redding, Connecticut.

Q. WHAT IS YOUR CURRENT BUSINESS AFFILIATION?

A. I am an independent financial and regulatory consultant working on behalf of several state public utility commissions and consumer advocates.

Q. PRIOR TO YOUR WORK AS AN INDEPENDENT CONSULTANT, WHAT WAS YOUR BUSINESS AFFILIATION, AND WHAT WAS YOUR REGULATORY EXPERIENCE?

A. I was a principal with the Georgetown Consulting Group for twenty years. During my affiliation with Georgetown, and continuing to date, I testified on cost of service, rate of return, and regulatory policy issues in more than 230 regulatory proceedings. These testimonies were presented before the Philadelphia Gas Commission, the Federal Energy Regulatory Commission and in the following jurisdictions: Alabama, Arizona, Colorado, Delaware, District of Columbia, Georgia, Illinois, Kansas, Maine, Maryland, Minnesota, Missouri, New Jersey, New Mexico, New York, Ohio, Oklahoma, Pennsylvania, Rhode Island, U.S. Virgin Islands, and Vermont.

Q. PRIOR TO JOINING GEORGETOWN, WHAT WAS YOUR BUSINESS EXPERIENCE?

A. For approximately five years I was employed by PepsiCo, Inc. in a series of positions. I began work as a Senior Business Planner on the corporate staff and then transferred to the Pepsi-Cola Company where I was Manager of Financial Services and later Director of Financial Services. I also served as Director of Financial Planning and Analysis for the Pepsi-Cola Bottling Group and as Vice-President of Finance for the Pepsi-Cola Equipment Corp.

My positions in finance with various Pepsi-Cola operations involved capital expenditure evaluation and budgeting, financial analysis, profit planning, financial reporting, and strategic planning. As Vice-President of Finance, I was responsible for all financial operations of the Pepsi-Cola Equipment Corp., a subsidiary of PepsiCo, Inc. My responsibilities as Vice-President included all accounting and data processing functions as well as portfolio management.

Prior to my work at PepsciCo, I was employed by Touche Ross & Co. in its Management Services Division. While at Touche Ross & Co. I was a Project Manager and worked on a broad range of consulting engagements. In addition to general financial and accounting engagements, I was involved to a considerable degree in utility regulation.

Q. COULD YOU SUMMARIZE SOME OF YOUR REGULATORY WORK WHILE AT TOUCHE ROSS?

A. While with Touche Ross, I analyzed utility filings and assisted in preparing testimony in approximately twelve state jurisdictions. I also worked for five city regulatory authorities, the Civil Aeronautics Board, and the Federal Communications Commission. In total, I was involved in about 40 rate investigations involving water, electric, bus transit, sewer, gas, telephone, airline, and cable utilities. My work involved rate of return, accounting, and tariff design for the majority of these utility groups.

Q. MR. LELASH, WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I graduated in 1967 from the Wharton School with a BS in Economics and in 1969 from the Wharton Graduate School with an MBA.

Q. DURING THE COURSE OF YOUR REGULATORY WORK, WHAT HAS BEEN YOUR EXPERIENCE WITH GAS POLICY AND PROCUREMENT?

A. Since 1980, I have worked extensively on gas policy and procurement issues. In my Appendix there is a listing of the recent cases in which I have sponsored testimony. In addition to these cases, I have reviewed and analyzed many other gas policy filings which were resolved through stipulation. Among other issues, my testimonies have involved gas service unbundling, physical and economic bypass, gas supply incentives, gas plant remediation costs, gas price hedging, demand and capacity planning, gas storage options, gas price forecasting, and least cost gas standards. In addressing these issues, I have analyzed gas regulatory filings involving about 30 different local distribution companies. During the past few years, I have worked on restructuring and unbundling matters for regulatory commissions or their staffs in Georgia, Delaware, and Rhode Island and for consumer advocates in New Jersey and Pennsylvania.

Q. DO YOU HAVE ANY SPECIFIC EXPERIENCE WITH RESPECT TO THE OPERATIONS OF PGW?

A. I have participated and provided testimony on behalf of the Public Advocate in all of PGW's Gas Cost Rate (GCR) proceedings throughout the 1990s and in the 2000 GCR proceeding before this Commission on behalf of the OCA. I also participated and provided testimony on behalf of the OCA in PGW's Interim Rates Case at Docket No. R-00005654 and PGW's Full Base Rate Case at Docket No. R-00006042.

Q. DO YOU HAVE ANY SPECIFIC EXPERIENCE WITH RESPECT TO NATURAL GAS COST RECOVERY AND THE RESTRUCTURING OF NATURAL GAS DISTRIBUTION COMPANIES IN PENNSYLVANIA?

A. Yes, in the past I have worked on and testified on behalf of the Pennsylvania OCA on gas cost recovery concerning seven of the Pennsylvania gas distribution companies in about a dozen 1307(f) proceedings. I also analyzed and presented testimony for the OCA concerning the restructuring filings of Columbia and PECO Energy.

## II. SCOPE AND PURPOSE OF TESTIMONY

Q. WOULD YOU PLEASE STATE THE SCOPE AND PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I was hired by the Office of Consumer Advocate ("OCA") to review the Gas Cost Rate ("GCR") filings made by the Philadelphia Gas Works ("PGW" or "Company") and evaluate them against established regulatory standards. My review focused on the gas costs and gas purchasing practices of the Company.

The purpose of my testimony is to present findings and recommendations to the Public Utility Commission ("PUC" or "Commission") concerning issues raised by the filings, PGW's gas procurement policy and practices, and the reasonableness of its proposed fiscal year 2001-2002 GCR factor.

Q. IN PERFORMING YOUR REVIEW AND ANALYSIS, WHAT DATA SOURCES DID YOU UTILIZE?

A. My review and analysis encompassed the Company's filings, responses to discovery requests, and information provided during discovery meetings. I also utilized information provided in previous GCR proceedings before the Philadelphia Gas Commission ("PGC") and general data concerning gas procurement and related gas cost recovery issues.

Q. WERE THERE ANY LIMITATIONS PLACED ON THE CONDUCT OF YOUR REVIEW?

A. In this proceeding, the Company has agreed to update its GCR calculations based on a July DRI wholesale gas price forecast. As a result, the recommended GCR factor derived in this testimony should be considered preliminary pending the Company's revision. I will supplement this testimony based on the Company's revision if necessary.

Additionally, this review utilized the data provided by the Company and no attempt was made to verify or validate the accuracy of the reported numbers. Finally, with the passage of the Natural Gas Choice and Competition Act ("Act"), there are several GCR related issues which are subject to legal interpretation. This testimony addresses such issues based on regulatory practice rather than from a legal perspective, and where necessary, legal conclusions were developed through consultation with Counsel.

## III. SUMMARY OF FINDINGS AND RECOMMENDATIONS

Q. BASED ON YOUR INVESTIGATION, WHAT ARE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING THE COMPANY'S GCR FACTOR AND ITS GAS PROCUREMENT FUNCTION?

A. As a result of my review and analysis, I make the following findings and recommendations:

The GCR Factor and Price Hedging

1. The Company's filing calculates a GCR factor of $5.5958 per MCF (all GCR amounts in this testimony exclude the $3.18 per MCF of gas costs which are recovered through base rates). Applying cost adjustments to the GCR calculation, the GCR factor should be changed to $4.4061 per MCF based on implementation as of September 1, 2001. The revised factor reflects lower levels of wholesale natural gas prices, increased margins or credits from off-system sales and capacity releases, a reduction to the cost of the CRP program commensurate with these price adjustments, and an assumption that the prior year's under recovery will be substantially reduced.

2. The majority of the decrease in the GCR factor is attributed to the recent decline in wholesale gas costs. The Company's filed gas costs were based on

the March Standard & Poor's DRI forecast. Using a more recent June DRI forecast shows average pricing for the 2001-2002 period which is $1.83 per MCF lower than the assumptions used by the Company. This price differential, when multiplied by forecasted volumes, equates to a $105.9 million gas cost reduction. Pending the Company's updated GCR calculation, based on the July DRI forecast, an interim $50.0 million reduction is recommended.

3. In addition, the lower wholesale gas costs will reduce or eliminate the Company's forecasted under recovery and will significantly lower the CRP expense which is contained in the Company's GCR factor. Again, pending the Company's update, the under recovery balance should be reduced by $10.0 million and the CRP expense should be reduced by $5.0 million. This latter amount reflects the effects of lower gas costs on the CRP offset by the recent increase in the number of customers enrolled in the program.

4. Embedded within the Company's Natural Gas Expense of $456.5 million is an implicit credit of $0.8 million for capacity release activities. Based on the last four years' average credits, a reasonable forecast would be $1.9 million, which is $1.1 million more than is reflected in the Company's GCR calculation.

5. In its filed GCR calculation, the Company omitted any forecasted contribution from off-system sales transactions. The associated off-system sales credits averaged $2.3 million for the past two years and there is no indication that the contribution cannot equal that level in the prospective GCR period. Accordingly, based on the trend for such sales, the current GCR determination should incorporate at least $2.0 million of additional credit for incremental off-system sales.

6. During the past GCR period, PGW locked-in gas prices for about 32.0 BCF of its gas purchases. This level of gas price hedging represented a reduction in the Company's on-going effort to reduce the price risk associated with its gas procurement. As a result of its 2000-2001 hedging, ratepayers' gas supply costs were lower than they would have been if gas supplies were purchased at prevailing market prices. Taking into account the effects of storage transactions, the hedging lowered the 2000-2001 cost, but will carry over relatively high cost inventory into 2001-2002.

<u>Gas Operations and Facilities</u>

7. During the past five years, PGW's firm demand has remained stable at about 60 BCF. With the relatively normal winter temperatures during the 2000-2001 GCR period, the Company had firm demand of 59.5 BCF as compared to the

normalized demand of 66.9 BCF which is forecasted for the upcoming period. Its peak winter demand occurred on December 25, when the average temperature was 20°F. Similar to past peak day requirements of 500 to 650 MMCF, the December 25 demand was 520 MMCF.

8. Prospectively, PGW expects its firm design day demand to be about 775 MMCF. This demand is met with about 445 MMCF of interstate pipeline supply with the remainder covered by the Company's daily availability of up to 540 MMCF of LNG vaporization. With the Company's need to restructure and to facilitate retail choice, it is appropriate that it reexamine its pipeline capacity contracts and seek to eliminate as much fixed demand charges as possible.

9. During the past five years, the Company has experienced an increase in its unaccounted for gas losses. During the last five years the losses have averaged 4.3% vs. the ten-year average of 3.9%. Based on the most recent data (1999-2000), unaccounted for gas losses of 7.3% would cost $17.1million per year if one assumes an incremental cost of $4.00 per MCF. However, it is likely that the high 1999-2000 losses reflect unbilled revenues. The Company should be required to explain the recent loss levels and isolate losses from unbilled revenues.

10. During the 2000-2001 GCR period, the Company experienced a relatively "normal" winter season. Its heating degree days ("HDD") were 4,602 which was 47 HDD (1.0%) above the current normalized level of 4,555 HDD. This weather reflects the fifth year in a row where HDD were essentially at or below the normal level.

11. With current wholesale gas price volatility, it is becoming increasingly more imperative for PGW to define objectives and procedures for its on-going gas price hedging. The Commission should require PGW to fully define the scope, control and financial exposure aspects of its prospective hedging initiatives. To date, the Company has not adopted any formal Financial Risk Management plan or clearly set forth the basic parameters of its physical contract hedging and use of financial hedges.

Gas Related Policy Issues

12. It will be necessary for PGW to make changes in both its operations and in how it recovers its gas costs in order to prepare for its restructuring and change in regulation. Operationally, it must gain flexibility by shortening the duration of its supply and capacity contracts and by staggering contract expirations to best match supply and demand in an unbundled gas market.

13. With the changes required by the Natural Gas Choice and Competition Act (Act), there is a continuing need for reevaluation of the inclusion of non-gas costs within the GCR and gas costs within base rates. For the past two years, it appears that the Company has recovered LNG Transportation Costs within the GCR. These costs, equaling $170,000 should be removed from the GCR reconciliation balance.

14. The Company has pursued appropriate regulatory objectives in its gas procurement. It has obtained lower cost gas supplies by utilizing physical contract hedges to lessen its exposure to price volatility. Likewise, it has been able to maintain its system reliability with respect to gas deliveries while at the same time obtaining capacity release and off-system margin credits to lower its overall GCR factor and by lowering its fixed capacity costs through gas portfolio enhancements. Accordingly, the Company has fulfilled the performance criteria which are generally applicable in 1307(f) proceedings.

## IV. THE GCR FACTOR AND RELATED ISSUES

Q. MR. LELASH, HAVE YOU REVIEWED THE COMPANY'S FILED CALCULATION FOR THE UPCOMING GCR FACTOR, AND DO YOU HAVE ANY ADJUSTMENTS WHICH YOU PROPOSE TO MAKE TO THAT FILED CALCULATION?

A. On Page 1 of Schedule 1, the Company's GCR factor is shown as filed, along with recommended adjustments which the Commission should make to the Company's calculation. In total, the Company is seeking recovery of $508.8 million of net applicable GCR expenses. These expenses and a September 1 implementation assumption underlie the calculation of a GCR factor of $5.5958 per MCF. Based on my analysis, it is recommended that the Commission adopt a GCR factor of $4.4061 per MCF to recover $440.7 million of gas costs assuming implementation effective September 1, 2001.

In order to provide a perspective on the current filing, a comparison is provided to the Company's prior year GCR request. This comparison is shown on page 2 of Schedule 1. As the data shows, despite the GCR reduction requested by the Company, its gas cost factor will still be $2.8017 per MCF above the level initially requested last year. Based on current gas forecasts, the GCR factor sought by the Company appears excessive.

- Determination of the GCR

Q. CURRENTLY, HOW DO THE NYMEX FUTURE'S PRICES COMPARE TO THOSE DURING THE PAST TWO YEARS?

A. The comparable data for the past two years and the current NYMEX futures prices are shown on page 4 of Schedule 1. These prices are actuals through July, 2001 and represent the prevailing futures prices thereafter. This data shows the sharp escalations in wholesale prices beginning in May 2000 and the start of price declines in May 2001. While prices have not returned to the $2.00 to $3.00 per dth levels seen during 1998-1999, there has been a substantial downward shift in the recent levels, and the longer-term futures prices confirm lower price expectations.

Q. WHAT IS THE BASIS FOR THE COMPANY'S ESTIMATED FUEL EXPENSES AND ARE THE UNDERLYING COMMODITY GAS PRICE ESTIMATES REASONABLE?

A. The Company has forecasted its gas commodity prices utilizing estimates prepared by Standard and Poor's. The estimates, which are referred to as DRI forecasts, are based on Standard and Poor's evaluation of a variety of factors, such as gas storage and demand, which affect future gas prices as measured by the NYMEX Henry Hub transactions. On page 5 of Schedule 1, the estimated rates for PGW's forecast are shown. This forecast incorporates the DRI estimates as of March, 2001. On the schedule, there are also columns showing the revised DRI forecast for June 2001, and the NYMEX futures prices as of the end of June, 2001.

As shown by the comparison of the two DRI forecasts, the average strip price for the September 2001 to August 2002 period has fallen by $1.83 per dth. In addition, during the most recent trading, the NYMEX strip price was $2.21 per dth below the price estimates on which the Company's gas cost projections were based. This would indicate that a substantial reduction to the Company's filed rate may be warranted.

Since the Company's cost of gas is affected by inventory transactions and gas price hedging activities, one cannot directly extrapolate a change in wholesale prices with a comparable change in gas costs. However, the Company, in its response to request OCA 1-35, reiterated its intention to rerun its gas cost model as soon as it receives its updated quarterly DRI forecast. Based on the June DRI estimates, the Company's gas costs would be $105.9 million lower than filed ($5.73 minus $3.90 per dth times 57.9 million dth). As a conservative estimate, pending the Company's update, a $50.0 million reduction has been factored into the recommended GCR factor shown on the first page of Schedule 1.

Q. WITH RESPECT TO THE NON-GAS COSTS, WHAT COMPONENTS ARE INCLUDED AND HOW DO THE FORECASTED AMOUNTS COMPARE WITH THE COMPANY'S PRIOR EXPENDITURES?

A. PGW's Non-Gas Costs, included in the GCR, are associated with Conservation Programs, the Customer Responsibility Program (CRP), and Purchased Electric. Several years of comparable historical data are shown on the first page of Schedule 2. As the schedule establishes, the forecasted amounts for both electric and conservation are generally in line with prior expenditure levels, and the estimated Customer Responsibility Program ("CRP") costs are forecasted to be about 16% lower than the 2000-2001 amount. Over recent years, the number of CRP customers has been declining from a total of about 61,000 in 1996-1997 down to the current average levels of about 50,000 as shown on page 2 of the schedule. In 2000-2001, with the substantial increase in gas commodity prices, the CRP costs increased, understandably, beyond past levels.

In general, prior to the recent GCR increases, the total CRP amounts have tracked the number of CRP customers. However, as the 2000-2001 expenditures show, the discount amount is highly sensitive to the GCR level. Accordingly, with the current decline in futures prices, I believe that the CRP estimate also needs to be reduced from the filed level. Therefore, the Company should be required to recompute its forecasted CRP expense to make it compatible with its revised gas cost estimate. Based on my calculations, an additional $5.0 million reduction is warranted based on my recommended gas cost amount and pending the Company's updated forecast.

This CRP expense reduction would have been considerably larger were it not for the fact that the program enrollment has apparently increased to in excess of 65,000 during the past few months. If such a level of CRP enrollment is sustained, then the favorable gas cost impact could be entirely eliminated. Accordingly, it is critical that the CRP expense be updated based on the new gas cost estimates, any revised enrollment estimates, and the expected level of grants such as LIHEAP which will be obtained.

Q. TURNING TO GCR RELATED CREDITS, DID YOUR REVIEW AND ANALYSIS INDICATE THE NEED FOR ANY ADJUSTMENT TO THE COMPANY'S ESTIMATES?

A. The Company has not included any pipeline refunds within its GCR calculation. Since no material refunds from the Company's pipelines are anticipated, this assumption appears reasonable and is reflective of the pipelines transition away from bundled merchant service.

Q. ARE THERE ANY CREDIT ADJUSTMENTS WHICH YOU WOULD RECOMMEND?

A. There are two which involve credits to the GCR for the Company's capacity release and off-system sales activity. In the current filing, the Company has included only an amount of $786,000 for capacity release credits. The historical levels for capacity release and off-system credits are shown on page 1 of Schedule 3. During the last two GCR periods, off-system credits have averaged $2.3 million per year. Based on the Company's existing capacity contracts and recent trends in release rates, I believe it is reasonable to anticipate that the Company will achieve credits equal to those averaged during the prior two years. Accordingly, I recommend that a $2.0 million off-system sales credit be incorporated into the GCR calculation.

Additionally, I believe that the Company's projected capacity release credits understate the amounts which can be realized during the 2001-2002 period. As shown on page 2 of Schedule 3, the capacity release credits have averaged about $2.5 million during the past four years. Despite this recent experience, the Company has included only $0.8 million as a credit to gas costs. On this page of Schedule 3, a calculation is provided in order to estimate an alternative capacity release credit amount. As the calculation shows, PGW expects the capacity release volumes to decrease and it has lowered the applicable credit rate per unit. My recommended adjustment is based on using the 2000-2001 forecasted volume and per unit rate. It is my understanding that capacity release credits are increasing in value and therefore the recommended credits which are $1.1 million higher than the Company's estimate appear more reasonable.

In a prior GCR proceeding, the Company noted that past capacity release credits were influenced by the fact that the degree days were well below normal and that this had the effect of increasing the credits which could be obtained. However, a high proportion of the release credits are associated with transactions during the shoulder months in the fall and spring of each GCR period and they would not necessarily be affected by low degree day levels. Additionally, to the degree that the applicable periods were milder than normal, it must also be assumed that demand was low and therefore the associated rates for capacity releases were also low. Finally, the 2000-2001 experienced credits which are recommended as the basis for the adjustment are associated with a year that had slightly higher than normal heating degree days.

On page 3 of Schedule 3, the gas cost adjustments are summarized. The three adjustments associated with off-system sales, capacity release credits, and the gas price adjustment are deducted from the Company's $456.5 million estimate to obtain a recommended amount of $403.4 million. This adjusted Applicable Fuel Expense is reflected on page 1 of Schedule 1. In addition, the schedule also has a memorandum entry reflecting interruptible margins. This entry is intended to note the that while the sales' cost of gas are credited to the GCR calculation, all associated interruptible margins are flowed through as base rate recoveries and, in effect, they provide inappropriate credits to the Company to the extent that they exceed the amount utilized in the last base rate setting.

Q. BASED ON THE ADJUSTMENTS WHICH YOU HAVE RECOMMENDED, WHAT OVERALL GCR FACTOR DO YOU BELIEVE SHOULD BE APPROVED?

A. On page 1 of Schedule 1, the derivation of my recommended $4.4061 per Mcf factor is shown. My recommended cost adjustments lower the Net Applicable GCR Expense by $58.1 million to an amount of $438.3 million. The schedule also reflects an adjustment in order to collect this expense amount assuming an implementation date of September 1. The associated derivation of the adjustment is shown on the second page of Schedule 1.

It should also be noted that the Company's forecasted prior period's under recovery of $12.4 million has been reduced by $10.0 million. With the lower than forecasted wholesale gas prices in effect for the last quarter of the 2000-2001 GCR period, it is anticipated that the Company will end the current GCR period only about $2.4 million under recovered. However, this is yet another GCR input which needs to be updated when the impact of the lower gas costs are determined. Based on the allocation of current gas costs to either flowing gas (used for current requirements) or storage inventory, the 2000-2001 reconciliation balance could be altered materially.

- <u>Gas Price Hedging Activity</u>

Q. WITH RESPECT TO THE COMPANY'S GAS COMMODITY PURCHASES, HAS THE PRICE HEDGING UTILIZED BY THE COMPANY REDUCED THE OVERALL COST OF GAS AND ITS PRICE VOLATILITY?

A. During the 2000-2001 GCR period, the Company locked in the prices for about 37.6 BCF of its gas requirements. This volume represents over 60% of the Company's firm demand, and it is reflective of the Company's use of gas price hedging to stabilize its customers' overall gas costs. The data provided on page 1 of Schedule 4 shows the level of gas price hedging during each of the prior three GCR periods. Over this time span, the Company has varied its hedging activities by utilizing between 30 and 50 BCF of price lock-ins.

These hedging positions have allowed the Company to reduce its price risk and to stabilize, to a degree, the costs of gas for its customers. The favorable results of the hedging have been highlighted by the gas prices during the past winter season. Unlike most LDCs, PGW had locked-in prices for its storage injection volumes and, as a result, some of its supply volume was purchased at prices which were well below the NYMEX indexed rates. It is appropriate to note that even LDCs which have active hedging programs, generally, did not take locked-in commodity positions comparable to those of PGW.

Q. HAVE YOU DEVELOPED ANY QUANTIFICATION OF THE GAS COST SAVINGS WHICH HAVE BEEN REALIZED BY THE COMPANY DURING THE 2000-2001 GCR PERIOD?

A. If one compares the Company's locked-in gas prices with the NYMEX's settle rates, one can derive an estimate of impact associated with the recent hedging activities. On the second page of Schedule 4, there is a calculation which quantifies the dollar spread between volumes at the locked in gas rates and at the monthly NYMEX settle prices for Henry Hub supply. In total, the net gas savings are shown to be about $27.9 million.

This measurement spans the April 2000 through March 2001 period because these purchases reflect the cost of gas used during the 2000-2001 GCR period. It also should be noted that the April through August purchases have an even more favorable impact if measured against prevailing gas costs in the month of use. Thus, while the April savings were estimated to be $2.1 million based on the April 2000 NYMEX price level of $2.88 per dth, since the storage supply was principally used during the December 2000 through February 2001 time period, it was displacing gas with prices between $6.02 and $9.91 per dth.

On a current basis, the hedging impact has not been as favorable. With wholesale natural gas prices falling from $9.91 per dth in January to $3.18 per dth in July, the hedging done this spring was at levels above the current market prices. It is my understanding that the majority of this year's hedged prices were allocated to inventory and therefore they will not materially affect the 2000-2001 cost of gas. On page 3 of Schedule 4 the hedging for the April 2001 through August 2001 period is shown. These transactions are unfavorable by $19.4 million if marked-to-market. However, since the gas will not be used until the winter of 2001-2002, these transactions could still have a net favorable price impact.

## V. GAS OPERATIONS AND FACILITIES

Q. WHAT IS THE OVERALL NATURE OF THE COMPANY'S OPERATIONS?

A. The Company serves about 520,000 firm customers in the City of Philadelphia. It distributes about 78.3 BCF of gas which it principally receives from two interstate pipelines. With the advent of FERC Order 636, the Company has converted much of its old supply entitlements into firm transportation. In addition to pipeline transportation, PGW has 3.9 BCF of LNG capacity, and it has maintained diversified storage contracts with its pipelines.

For now, and into the future, gas price uncertainty is a major concern for the Company's gas procurement function. With the various FERC orders which restructured the gas supply market, utilities such as PGW face market-based gas prices which have been very volatile over the past few years.

Q. WOULD YOU DESCRIBE THE BASIC PARAMETERS OF THE COMPANY'S GAS SERVICE?

A. PGW's gas demand has been relatively stable during the past five years. Its highest annual demand was experienced in the 1996-1997 period when system firm sales were over 59.6 BCF. This is in contrast to the Company's firm demand for 1999-2000 which fell to about 54.5 BCF because of the mild winter heating season. On page 1 of Schedule 5, the sales volumes by customer classification are provided for the past five

GCR periods. As shown by this data, the majority of the Company sales are made to the residential rate classifications. The interruptible rate classifications, which utilized about 10.1 BCF of gas during 1996-1997, are projected to use only 7.5 BCF in 2000-2001 which is a 25.7% decrease from the prior level.

Because of its customer characteristics, the Company's load factor is quite low. The Company has a significant summer-winter use differential principally because of its high proportion of residential heating customers. On an annual basis, the Company's firm sales have declined during the past few years. However, as shown on page 2 of Schedule 5, any variation in demand generally coincides with variation in annual degree days. Thus, weather normalized sales have been relatively stable.

On page 3 of Schedule 5, PGW's customer levels are shown by classification, and on page 4 of the same schedule, per customer usage statistics are provided. The figures show that PGW has been losing non-heating customers in most service categories. However, this has been offset to a degree by conversions over to heating service. Overall, firm customers have decreased by 2.7% since 1996-1997, and usage per customer has stayed relatively stable for all heating customer classes.

Q. WHAT HAS BEEN PGW'S RECENT HISTORY CONCERNING PEAK DAY DEMAND AND SUPPLY?

A. During the last five GCR periods, the Company's highest peak demand was 662 MMCF. This requirement occurred on January 18, 1997 when the average daily temperature was

12 degrees. As shown on page 1 of Schedule 6, the Company typically meets the majority of its peak day requirements through pipeline supplied natural gas. Accordingly, it has been able to meet peak demand with the use of less than 250 MMCF of daily LNG capacity.

These statistics concerning peak day requirements are utilized by the Company so that it can match its gas supply with its system requirements. While no load duration curves for PGW were studied, it does appear that daily requirements at or near the design peak are relatively limited in number, and they can be supplied by existing capacity.

Q. WHAT ARE THE SPECIFICS OF THE COMPANY'S DEMAND AND SUPPLY FORECASTS FOR ITS DESIGN DAY PLANNING?

A. The Company's forecast for design day demand and supply is shown on page 2 of Schedule 6. As indicated, PGW has about a 20% to 25% reserve margin on supply through the year 2007. This reserve margin, when expressed in terms of LNG supply, shows that design day demand would only utilize about 330 to 370 MMCF of LNG out of a daily availability of up to 540 MMCF. Thus, almost 40% of the LNG daily capacity could theoretically be utilized to cover pipeline curtailments.

It should also be noted that in addition to maintaining adequate capacity to meet its peak day demand on a reliable basis, the Company has been able to steadily reduce its associated fixed demand charges on capacity (see Schedule 6, page 2). It has done this by restructuring its capacity and by achieving substantial capacity credits. By referring back to page 1 of Schedule 3, it can be seen that capacity credits have been between \$3.8 million and \$4.7 million during the past three years.

Q. WHAT HAVE BEEN PGW'S HISTORIC LEVELS FOR GAS LOSSES AND ARE THE FORECAST AMOUNTS FOR THE 2001-2002 GCR REASONABLE?

A. During the last five years, for which data is available, PGW's unaccounted for gas has ranged between 2.2% and 7.3% of its sendout volumes (see page 1 of Schedule 7). Unaccounted for gas is only measured for the twelve months ending in August, and therefore, no percentage has been provided for the 2000-2001 GCR period. Based on the average loss level, PGW's experienced losses are higher than those of other LDCs. Moreover, there has been an elevation in the level of losses during the recent periods.

Whether this constitutes a trend or is merely a temporary change is not known at this time. It is assumed that the sharp increase in the loss percentage in 1999-2000 was associated with unbilled revenues. Such unbilled revenues would increase the differential between sendout and billed volumes, thereby inflating the loss amount. Accordingly, the Company should be required to analyze and, if warranted, break out any unbilled revenue effect on the 1999-2000 measurement. Such a subsequent analysis should be completed and filed with the PUC no more than 60 days after the end of its 2000-2001 fiscal year. This deadline is particularly relevant because PGW has not fulfilled the Commission's prior requirement "to determine why the level of unaccounted for gas losses continues to rise" (Docket No. R-00005619, Ordering Paragraph No. 6). It is recommended that the contemplated report specify the portion of gas losses attributed to unbilled gas usage related to "data conversion and customer billing problems" as stated in the Company's Monthly GCR Progress Reports. The report should also document the adjustments which PGW makes for variations in gas pressure, losses from construction, gas main breaks, system leaks, and other such factors. Also, the subsequent measurement of the losses for the 2000-2001 GCR period should be analyzed further if it is not comparable to the average prior to 1999-2000. With regard to the unaccounted gas loss forecast for the prospective GCR period, the Company has utilized a 4.2% loss allowance. This rate is higher than the Company's recent experience, and it should be modified to the five year (3.6%) or ten year (3.9%) rates prior to 1999-2000 to eliminate what hopefully is an atypical measurement.

Q. DO YOU BELIEVE THAT THE LEVEL OF, AND TREND IN, UNACCOUNTED FOR GAS LOSSES WARRANTS ADDITIONAL ANALYSIS?

A. In the past, management has analyzed this issue and there are indications that a refocused effort to replace distribution mains and services is warranted. At loss levels above 4.0%, there is a need to analyze various loss factors, and should the loss rate go any higher, or should the 1999-2000 measurement be accurate, it would be appropriate to initiate remedial efforts.

Q. WOULD YOU PLEASE DESCRIBE THE COMPANY'S DEGREE DAY MEASUREMENTS FOR PRIOR YEARS?

A. The Company's last eight GCR years' degree day levels are shown on page 2 of Schedule 7. The Company's normal year has a total of 4,555 degree days. As shown on the schedule, the Company has had significant degree day variation during the past few GCR periods. During the 1998-1999 GCR period, the experienced annual degree days were only about 85.4% of normal while the 1995-1996 GCR period exceeded normal by 14.7%.

While the data on the second page of Schedule 7 would appear to indicate a warming trend, analyses performed in the context of last year's GCR review indicated that such a trend is not inherent in the degree day statistics. While three successive years with degree days 12% or more below normal is clearly unusual, it does not indicate any predictive trend concerning the weather to be experienced in 2001-2002. Based on accepted meteorological forecasting procedures, there remains a 50%-50% probability that degree days will be higher or lower than the long-term 4,555 degree day average.

## VI. GAS RELATED POLICY ISSUES

Q. WHAT POLICY ISSUES DO YOU WISH TO DISCUSS CONCERNING PGW'S GAS PROCUREMENT?

A. In this part of the testimony, several policy areas will be discussed to follow up on past PUC requirements and concerning issues where PGW should be required to take future actions concerning its procurement. These issue areas do not directly affect the 2001-2002 GCR factor, but they are relevant to PGW's continued ability to provide least cost procurement of its required natural gas supply.

### Gas Price Hedging Guidelines

Q. WHAT IS THE CURRENT STATUS ON THE COMPANY'S GAS PRICE HEDGING ACTIVITIES?

A. As reflected in the Company's Monthly GCR Progress Reports, the Company has done little to respond to the Commission's prior order concerning hedging. The Commission required that PGW "define its objectives and procedures for its on-going gas price hedging, including the scope, control, and financial exposure aspects of its prospective hedging initiatives" (Docket No. R-00005619, Ordering Paragraph No. 2). With the exception of its forming a Gas Supply Committee, the Company has not defined either its objectives or its procedures for gas price hedging.

Within its Monthly GCR Progress Reports the Company has not explained how the Gas Supply Committee manages and controls the hedging, and it has not specified how the transactions are authorized. Likewise, there are no formal objectives for its hedging program, the Company has not determined whether or not financial hedging should be used, and there are no stated parameters for minimum and maximum limits concerning the level of positions taken during any period of time. As a consequence, the Company's approach to hedging varies from season to season.

This is not to say that the Company's hedging objectives and procedures are not reasonable, but rather they have not been formalized nor have they been made known to the PUC or other parties to the GCR reviews. In the past, the Company provided a draft Financial Risk Management Policy which apparently has yet to be finalized. As stated in last year's testimony, "sound policy requires that the hedging be conducted with parameters which have been evaluated and approved by the Commission."

It is therefore recommended that the Commission direct the Company to develop and file a formalized Risk Management Program which addresses its hedging objectives and strategies. The program should also specify the nature, timing, and dollar or volume limits for hedging and discuss whether or not financial hedging is to be done and why. This envisioned program should be filed within 90 days from the Commission's Order in this proceeding.

General Policy Issues

Q. ARE THERE ANY OTHER GCR RELATED ISSUES WHICH YOU WISH TO DISCUSS?

A. Yes, there are several issue areas which warrant comment. The first involves the Company's request for waivers of the provisions of Sections 11.2.6 and 11.3 of PGW's Gas Service Tariff. Such waivers are reasonable in light of the volatility of wholesale natural gas prices and based on the factors discussed on pages 11 and 12 of Mr. White's direct testimony. Accordingly, it is recommended that the PUC grant such waivers as it did in Docket No. R-00005619.

A second issue involves the allocation of costs between base rate and GCR recovery. While it is understood that this issue is to be addressed in the pending base rate case, it is necessary to state that any GCR factor derived in this proceeding will have to be adjusted accordingly. On Schedule 8, I have listed the various cost components which need to be coordinated with the base rate order. Presumably, any cost reallocations could be implemented in PGW's December 1, 2000 GCR quarterly filing, which would be the first quarterly update after the PUC Order in the base rate proceeding is issued. It is therefore recommended that any GCR factor adopted in this proceeding be made subject to any associated PUC ordered cost reallocations.

Additionally, based on the Company's Response to OTS-1-6, it appears that PGW has included $170,946 of LNG Transportation costs within its GCR reconciliation. To my knowledge, neither the PGC nor the PUC has ever authorized recovery of such costs through the GCR. Therefore, since such costs are not included within the definition of Non-Gas Expenses in Section 11.5 of the tariff, they should be removed from the Factor E calculations.

Third, it should be recognized, in developing the prospective GCR factor, that how the Company allocates gas purchases during the storage injection period will have a material effect on both the past year's reconciliation and the appropriate level of the prospective GCR rate. Accordingly, the Company should be required, as part of its updated gas cost calculations, to specify its associated allocation of gas costs between flowing supplies and storage during the March 2001 through August 2001 period. By having the Company make such a specification, the parties and the PUC will be able to determine whether or not prospective gas costs are predicated on storage or flowing gas priorities within the updated forecast.

Fourth, the Company acknowledged, in its Response OCA 1-14, that PGW's gas supply contracts have not been "duly authorized and signed pursuant to existing requirements." This situation, while associated with the FERC's unbundling of merchant service, has been allowed to persist for too long. While the Company has detailed actions which might remedy the deficiency, a deadline for resolution of this issue should be set. Accordingly, the Commission should require that PGW provide it with a status update on the issue within 60 days from the date of its order and that the deficiency be resolved within 180 days from the date of its order.

Q. ARE THERE ANY OTHER MATTERS WHICH YOU WISH TO COMMENT UPON?

A. Based on concerns raised in previous proceedings, it is appropriate to comment upon the Company's LNG project and its mains replacement program. Both the LNG facility and mains infrastructure are critical to PGW's overall system reliability. As such, they play a vital role to ensure safe and adequate service and as an integral part of PGW's procurement.

With respect to the mains program, the Company has replaced 40,703 feet of mains (or about 8 miles out of the targeted 18 miles of replacement). Since the majority of the mains replacement work is done during the summer, it is anticipated that the 1% replacement objective will be met during the current fiscal year. The only related recommendation would be for the Company to include on-going data, perhaps in its Monthly GCR Progress Report, concerning budgeted mains replacement footage and actually achieved footage, with a short narrative if the Company believes that it will not achieve its established annual objective.

As for the LNG project, through June, the Company reports that the project is over 50% complete. At the present time, site mobilization is scheduled for August, which is one month later than originally planned. However, the Company has not altered its expected in service date of March 2002. On a related matter, the Company should be directed to update its LNG Business Strategy which was last submitted in 1998. With the open expander and other LNG upgrades, it is appropriate that PGW reassess its LNG strategy in order to maximize the on-going value of the facility within the procurement process.

<u>Assessment of PGW's Gas Procurement</u>

Q. BASED ON YOUR REVIEW OF PGW'S GAS PROCUREMENT, DOES THE COMPANY FULFILL THE PERFORMANCE CRITERIA WHICH ARE GENERALLY APPLICABLE IN 1307(F) PROCEEDINGS?

A. Yes, subject to the issues raised in this testimony, it does. The Company has initiated a number of actions to obtain lower cost gas supplies for its customers. For example, it has negotiated various gas portfolio enhancements which have lowered its overall fixed capacity costs. It also has utilized gas price hedging strategies in order to reduce its gas price volatility and lessen its exposure to gas cost increases. Additionally, over the past few years it has been able to reduce the average duration of its gas supply and capacity contracts in order to obtain greater supply flexibility. In terms of capacity utilization, it has pursued off-system and capacity release activities which have made a significant contribution to lower overall GCR costs. These activities have included sales of its LNG peaking capacity to other LDCs in addition to the typical capacity transactions.

Q. COULD YOU PROVIDE GREATER DETAIL CONCERNING SOME OF THESE REFERENCED PROCUREMENT ACTIVITIES?

O. As previously discussed, the Company's gas price hedging during 2000-2001 saved at least $27.9 million in gas costs based on a price comparison to the NYMEX monthly index. The supporting data, shown on page 2 of Schedule 4, shows that the hedged volumes, which generally were used for storage injection, benefitted customers during the 2000-2001 winter season. In addition to moderating its commodity cost of gas, the Company's capacity transactions and gas portfolio enhancements have reduced fixed gas costs by $12.9 million during the past four GCR periods (*see* page 3 of Schedule 6).

Q. HOW HAS PGW'S PERFORMANCE BEEN WITH RESPECT TO OTHER 1307(F) CRITERIA?

A. The Company is not affiliated with any pipeline or gas supply operation, nor does it have any contracts for local production. Accordingly, the Company is not able, in the traditional sense, to withhold from the market any gas supplies which should be part of a least cost gas procurement program. In the one context where PGW does have discretion concerning supply utilization, that being its use of storage inventories, it has not historically withheld storage gas from use.

Additionally, PGW has typically represented its ratepayers in proceedings at the FERC. Its Federal Regulatory Affairs Department has actively monitored FERC proceedings and has intervened in several cases where the litigation might affect PGW's ratepayer interests. In the past, the Company has principally intervened and filed comments in Transco, Texas Eastern, ANR, CNG, and Equitrans matters. However, it has also participated in some rulemaking proceedings, and on occasion it has filed Petitions for Review to challenge certain FERC Opinions and Orders.

In summary, through a variety of procurement activities and initiatives, PGW has pursued a program which has lowered its gas supply costs, ensured on-going gas supply reliability, and better positioned the Company for the competitive gas supply market.

Q. MR. LELASH, DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does, but I would like to reserve my right to change or supplement this testimony based on any new information or updates which may become available.

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# VII. SUPPORTING SCHEDULES

# Philadelphia Gas Works

## Index of Supporting Schedules

**Philadelphia Gas Works**
**2001-2002 GCR Factor**
**(000's)**

| | As Filed | Difference | Recommended |
|---|---|---|---|
| Applicable Sales Volume | 57,889 | | 57,889 |
| Expenses - Fuel | | | |
| Total Applicable Fuel Expense | $456,486 | $ (53,068) | $403,418 |
| Expenses - Non-Fuel | | | |
| Conservation Programs | $ 2,200 | $ - | $ 2,200 |
| CRP Discounts | 37,696 | (5,000) | 32,696 |
| Total Applicable Non-Fuel Expense | $ 39,896 | $ (5,000) | $ 34,896 |
| Applicable GCR Expense | $496,382 | $ (58,068) | $438,314 |
| Adjustment For: | | | |
| Gas Refunds | $ 0 | $ - | $ 0 |
| Prior Year Reconciliation | 12,375 | (10,000) | 2,375 |
| Total Adjustment | $ 12,375 | $ (10,000) | $ 2,375 |
| Net Applicable GCR Expense | $508,757 | $ (68,068) | $440,689 |
| Applicable Unit GCR Expense | $ 8.7886 | $ - | $ 7.5861 |
| Base Fuel Cost Recovery | 3.1800 | | 3.1800 |
| Applicable GCR Factor (per MCF) | $ 5.5958 | $ (1.1897) | $ 4.4061 |

SOURCES: PGW's 2001-2002 GCR Filing and Schedule 1, page 3.

**Philadelphia Gas Works**
**2001-2002 GCR Factor**
**(000's)**

| | 2000/2001 | Difference | 2001/2002 |
|---|---|---|---|
| Applicable Sales Volume | 57,221 | 668 | 57,889 |
| Expenses - Fuel | | | |
| Total Applicable Fuel Expense | $306,622 | $149,864 | $456,486 |
| Expenses - Non-Fuel | | | |
| Conservation Programs | $ 2,200 | $ - | $ 2,200 |
| CRP Discounts | 28,242 | 9,454 | 37,696 |
| Total Applicable Non-Fuel Expense | $ 30,442 | $ 9,454 | $ 39,896 |
| Applicable GCR Expense | $337,064 | $159,318 | $496,382 |
| Adjustment For: | | | |
| Gas Refunds | $ 0 | $ - | $ 0 |
| Prior Year Reconciliation | 3,663 | 8,712 | 12,375 |
| Total Adjustment | $ 3,663 | $ 8,712 | $ 12,375 |
| Net Applicable GCR Expense | $340,727 | $168,030 | $508,757 |
| Applicable Unit GCR Expense | $ 5.9741 | $ 2.8017 | $ 8.7886 |
| Base Fuel Cost Recovery | 3.1800 | - | 3.1800 |
| Applicable GCR Factor (per MCF) | $ 2.7941 | $ 2.8017 | $ 5.5958 |

SOURCES: PGW's 2000-2001 and 2001-2002 GCR Filings.

**Philadelphia Gas Works**
**2000-2001 GCR Factor**
**(000's)**

| | |
|---|---|
| 1. Total Applicable GCR Sales | 57,889 |
| 2. Base Fuel Factor | $ 3.18 |
| 3. Base Fuel Recoveries (L1 times L2) | $184,087 |
| 4. GCR Sales - Through September 15th | 672 |
| 5. Current GCR Factor | $ 6.6959 |
| 6. Recoveries Through September 15th (L4 times L5) | $ 4,500 |
| 7. GCR Sales - After September 15th (L1 minus L4) | 57,217 |
| 8. Net Applicable GCR Expenses ($440,689 minus L3, L6) | $252,102 |
| 9. Applicable GCR Factor (L8 divided by L7) | $ 4.4061 |

SOURCE: Informal PGW Discovery Response.

**Philadelphia Gas Works**
**NYMEX Henry Hub Price Comparisons**

| | 1999/2000 | 2000/2001 | 2001/2002 (futures) |
|---|---|---|---|
| September | $2.90 | $4.62 | $3.17 |
| October | 2.55 | 5.29 | 3.26 |
| November | 3.06 | 4.50 | 3.54 |
| December | 2.14 | 6.02 | 3.82 |
| January | 2.36 | 9.91 | 3.90 |
| February | 2.61 | 6.22 | 3.80 |
| March | 2.61 | 5.03 | 3.63 |
| April | 2.88 | 5.35 | 3.38 |
| May | 3.08 | 4.87 | 3.36 |
| June | 4.37 | 3.73 | 3.41 |
| July | 4.36 | 3.18 | 3.46 |
| August | 3.83 | 3.10 | 3.48 |
| Averages | $3.06 | $5.15 | $3.52 |

SOURCE: Standard & Poor's DRI Monthly Natural Gas Price Outlook, June, 2001 and NYMEX Settle Prices as of June 29, 2001.

**Philadelphia Gas Works**
**DRI Forecasts vs. NYMEX**
**Henry Hub Per Dth**

| | March DRI Forecast | July DRI Forecast | NYMEX |
|---|---|---|---|
| September 2001 | $6.11 | $3.50 | $3.17 |
| October | 6.25 | 3.72 | 3.26 |
| November | 6.41 | 4.00 | 3.54 |
| December | 6.56 | 4.24 | 3.82 |
| January 2002 | 5.67 | 4.34 | 3.90 |
| February | 5.17 | 4.31 | 3.80 |
| March | 5.08 | 4.13 | 3.63 |
| April | 5.37 | 3.73 | 3.38 |
| May | 5.54 | 3.66 | 3.36 |
| June | 5.65 | 3.70 | 3.41 |
| July | 5.51 | 3.74 | 3.46 |
| August | 5.41 | 3.76 | 3.48 |
| Averages | $5.73 | $3.90 | $3.52 |

SOURCE: Standard & Poor's DRI Monthly Natural Gas Price Outlook for March and June 2001, NYMEX Futures Contracts, June 29, 2001.

**Philadelphia Gas Works**
**GCR Non-Gas Cost Components**
**($000's)**

| GCR Period | CRP Costs | Conservation | Electric | Totals |
|---|---|---|---|---|
| 1994-1995 | $15,122 | $2,093 | $1,154 | $18,369 |
| 1995-1996 | 23,103 | 1,992 | 1,017 | 26,112 |
| 1996-1997 | 17,763 | 2,162 | 999 | 20,924 |
| 1997-1998 | 11,970 | 1,705 | 954 | 14,629 |
| 1998-1999 | 11,081 | 996 | 752 | 12,829 |
| 1999-2000 | 14,783 | 2,047 | 1,016 | 17,846 |
| 2000-2001 (A/E) | 44,736 | 2,200 | 965 | 47,901 |
| 2001-2002 | $37,696 | $2,200 | $1,370 | $41,266 |

SOURCES: Company Response OCA 1-18 and Company GCR Filing, Tab 2, Sheet 1.

**Philadelphia Gas Works**
**Comparative CRP Customers**

| | 2000-2001 | 2001-2002 |
|---|---|---|
| September | 54,072 | 49,000 |
| October | 54,542 | 49,500 |
| November | 55,396 | 50,000 |
| December | 55,261 | 50,500 |
| January | 55,764 | 51,000 |
| February | 56,000 | 51,000 |
| March | 56,000 | 51,500 |
| April | 56,000 | 52,000 |
| May | 54,000 | 51,000 |
| June | 51,000 | 50,000 |
| July | 49,000 | 49,000 |
| August | 49,000 | 49,000 |
| Average | 53,836 | 50,292 |

NOTE: Customer levels are actual through January 2001 and estimated thereafter.

SOURCE: Company Response OCA 1-37, Attachment 6.

**Philadelphia Gas Works**
**Refunds, Capacity and Margin Credits**
**($000's)**

| GCR Period | Refunds | Capacity Release | Off-System Margins | Total Credits |
|---|---|---|---|---|
| 1994-1995 | $9,981 | $ 917 | $ 315 | $11,213 |
| 1995-1996 | 2,421 | 463 | 1,890 | 4,774 |
| 1996-1997 | 3,151 | 504 | 2,078 | 5,733 |
| 1997-1998 | 170 | 2,230 | 355 | 2,755 |
| 1998-1999 | 3,710 | 3,798 | 19 | 3,817 |
| 1999-2000 | -0- | 2,310 | 2,379 | 4,689 |
| 2000-2001 (A/E) | 4,999 | 1,854 | 2,202 | 9,055 |
| 2001-2002 | -0- | 786 | -0- | 786 |

SOURCES: Company GCR Filing, Tab 2, Sheet 5, and Responses to OCA 1-26 and 1-30.

**Philadelphia Gas Works**
**Forecast vs. Prior Credits**

| GCR Period | Volume (000's) | Release Credits ($000's) | Credits Per Dth |
|---|---|---|---|
| 1997-1998 | 16,098 | $2,230 | $0.139 |
| 1998-1999 | 18,475 | 3,798 | 0.206 |
| 1999-2000 | 18,748 | 2,310 | 0.123 |
| 2000-2001 | 17,392 | 1,854 | 0.107 |
| Averages | 17,678 | 2,548 | 0.144 |
| 2001-2002 | 15,899 | 786 | 0.049 |
| Recommended | 17,392 | 1,854 | 0.107 |
| Difference | - | 1,068 | 0.058 |

SOURCE: Company Response OCA 1-26.

**Philadelphia Gas Works**
**Fuel Expense Adjustments**
**($000's)**

| | As Filed | Difference | Recommended |
|---|---|---|---|
| Natural Gas Expense | $455,902 | $ - | $455,902 |
| Purchased Electric | 1,370 | - | 1,370 |
| Interruptible Margins | -0- | - | -0- |
| Off-System Sales | -0- | (2,000) | (2,000) |
| Capacity Release Credits | (786) | (1,068) | (1,854) |
| Gas Price Adjustment | -0- | (50,000) | (50,000) |
| Applicable Fuel Expense | $456,486 | $(53,068) | $403,418 |

SOURCE: Schedules 1, 2, and 3.

**Philadelphia Gas Works**
**Locked-In Gas Volumes**
**(000's Dth)**

| | 1998-1999 | 1999-2000 | 2000-2001 | 2001-2002 (forecasted) |
|---|---|---|---|---|
| September | 3,600 | 3,750 | 2,430 | 2,700 |
| October | 3,720 | 4,340 | 3,100 | 2,790 |
| November | 3,600 | 3,788 | 1,800 | 7,590 |
| December | 3,720 | 4,294 | 1,860 | 7,843 |
| January | 3,720 | 4,379 | 1,550 | 7,843 |
| February | 3,458 | 4,096 | 2,800 | 4,358 |
| March | 3,720 | 4,650 | 2,635 | 4,433 |
| April | 2,864 | 3,900 | 2,550 | - |
| May | 2,635 | 3,875 | 3,415 | - |
| June | 2,700 | 3,300 | 3,300 | - |
| July | 3,255 | 3,410 | 3,725 | - |
| August | 3,286 | 3,255 | 2,790 | - |
| | 40,277 | 47,036 | 31,955 | 37,557 |

SOURCES: Company GCR Schedules and Response OCA 1-39 and 1-40.

**Philadelphia Gas Works**
**2000-2001 Price Hedging**

| | Hedged Volumes Mdth | Monthly Lock In | Monthly NYMEX | Price Spread | Dollar Spread (000's) |
|---|---|---|---|---|---|
| April 2000 | 3,900 | $ 2.33 | $2.88 | $ 0.55 | $ 2,145 |
| May | 3,875 | 2.29 | 3.08 | 0.79 | 3,061 |
| June | 3,300 | 2.30 | 4.37 | 2.07 | 6,831 |
| July | 3,410 | 2.31 | 4.36 | 2.05 | 6,991 |
| August | 3,255 | 2.30 | 3.83 | 1.53 | 4,980 |
| September | 2,430 | 4.53 | 4.62 | 0.09 | 219 |
| October | 3,100 | 5.06 | 5.29 | 0.23 | 713 |
| November | 1,800 | 4.97 | 4.50 | (0.47) | (846) |
| December | 1,860 | 4.93 | 6.02 | 1.09 | 2,027 |
| January 2001 | 1,550 | 4.91 | 9.91 | 5.00 | 7,750 |
| February | 2,800 | 7.41 | 6.22 | (1.19) | (3,332) |
| March | 2,635 | 6.04 | 5.03 | (1.01) | (2,661) |
| Total | | | | | $27,878 |

SOURCE: Company Response OCA 1-39 and Schedule 1, page 4.

**Philadelphia Gas Works**
**2001-2002 Price Hedging**

| | Hedged Volumes Mdth | Monthly Lock In | Monthly NYMEX | Price Spread | Dollar Spread (000's) |
|---|---|---|---|---|---|
| April 2001 | 2,550 | $5.25 | $ 5.35 | $ 0.10 | $ 255 |
| May | 3,415 | 5.23 | 4.87 | (0.36) | (1,229) |
| June | 3,300 | 5.26 | 3.73 | (1.53) | (5,049) |
| July | 3,725 | 5.17 | 3.18 | (1.99) | (7,413) |
| August | 2,790 | 5.22 | 3.10 | (2.12) | (5,915) |
| Total | | | | | $(19,351) |

SOURCE: Company Response OCA 1-39 and Schedule 1, page 4.

**Philadelphia Gas Works**
**Annual Sales Volumes**
**(MMCF)**

| Customer Class | 1996-1997 | 1997-1998 | 1998-1999 | 1999-2000 | 2000-2001 (A/E) |
|---|---|---|---|---|---|
| Heating: | | | | | |
| Residential | 36,560 | 33,658 | 34,154 | 39,295 | 36,033 |
| CRP | 7,852 | 6,006 | 5,462 | (247) | 6,504 |
| Commercial | 6,794 | 6,117 | 6,404 | 8,192 | 8,932 |
| Industrial | 867 | 766 | 794 | 844 | 971 |
| Other | 2,531 | 2,259 | 2,200 | 1,849 | 1,973 |
| Total Heating | 54,605 | 48,805 | 49,014 | 49,933 | 54,413 |
| Non-Heating: | | | | | |
| Residential | 2,031 | 1,954 | 1,902 | 1,954 | 2,064 |
| CRP | 222 | 162 | 136 | (14) | 201 |
| Commercial | 1,878 | 1,832 | 1,777 | 1,920 | 1,958 |
| Industrial | 651 | 540 | 612 | 456 | 605 |
| Other | 285 | 268 | 244 | 278 | 239 |
| Total Non-Heating | 5,067 | 4,755 | 4,671 | 4,594 | 5,067 |
| Total Firm | 59,672 | 53,560 | 53,685 | 54,527 | 59,480 |
| Interruptible | 10,091 | 9,879 | 8,441 | 8,615 | 7,459 |
| Total Volumes | 69,763 | 63,439 | 62,126 | 63,142 | 66,939 |

SOURCES: Company's Annual GCR Filings and Response OCA 1-24.

**Philadelphia Gas Works**
**Normalized Firm Volumes**

| GCR Period | Sales (MMCF) | Actual Degree Days | Normal Degree Days | Adjustment Factor | Normalized Sales |
|---|---|---|---|---|---|
| 1993-1994 | 65,344 | 5,002 | 4,555 | 1.098 | 59,505 |
| 1994-1995 | 56,210 | 4,206 | 4,555 | 0.923 | 60,874 |
| 1995-1996 | 65,371 | 5,223 | 4,555 | 1.147 | 57,010 |
| 1996-1997 | 59,672 | 4,667 | 4,555 | 1.025 | 58,240 |
| 1997-1998 | 53,560 | 4,003 | 4,555 | 0.879 | G60,946 |
| 1998-1999 | 53,685 | 3,892 | 4,555 | 0.854 | 62,830 |
| 1999-2000 | 54,527 | 3,979 | 4,555 | 0.874 | 62,420 |
| 2000-2001 | 59,480 | 4,602 | 4,555 | 1.010 | 58,872 |
| Average | 58,481 | 4,447 | 4,555 | 0.976 | 59,901 |
| 2001-2002 | 61,187 | 4,555 | 4,555 | 1.000 | 61,187 |

SOURCES: Company Response OCA 1-21, 2nd Quarter Update.

**Philadelphia Gas Works**
**Number of Customer Billings**

| Customer Class | 1996-1997 | 1997-1998 | 1998-1999 | 1999-2000 | 2000-2001 |
|---|---|---|---|---|---|
| Heating: | | | | | |
| Residential | 371,150 | 378,128 | 376,561 | 372,544 | 374,123 |
| CRP | 57,487 | 47,995 | 43,294 | 46,972 | 47,775 |
| Commercial | 17,893 | 17,801 | 17,758 | 18,597 | 20,327 |
| Industrial | 767 | 756 | 766 | 735 | 824 |
| Other | 4,888 | 5,280 | 5,217 | 5,114 | 5,067 |
| Total Heating | 452,185 | 449,960 | 443,596 | 443,962 | 448,116 |
| Non-Heating: | | | | | |
| Residential | 72,917 | 70,537 | 67,991 | 67,153 | 64,217 |
| CRP | 3,639 | 2,563 | 2,034 | 2,207 | 2,433 |
| Commercial | 6,398 | 6,197 | 6,146 | 6,111 | 5,849 |
| Industrial | 398 | 401 | 407 | 388 | 389 |
| Other | 316 | 393 | 395 | 360 | 359 |
| Total Non-Heating | 83,668 | 80,091 | 76,973 | 76,219 | 73,247 |
| Total Firm | 535,853 | 530,051 | 520,569 | 520,181 | 521,363 |
| Interruptible | 441 | 467 | 475 | 491 | 513 |
| Total Customers | 536,294 | 530,518 | 521,044 | 520,672 | 521,876 |

SOURCES: Company's Annual GCR Filings and Response OCA 1-24.

**Philadelphia Gas Works**
**Average Customer Usage**
**(MMCF)**

| Customer Class | 1996-1997 | 1997-1998 | 1998-1999 | 1999-2000 | 2000-2001 |
|---|---|---|---|---|---|
| Heating: | | | | | |
| Residential | 99 | 89 | 91 | 105 | 96 |
| CRP | 137 | 125 | 126 | (5) | 136 |
| Commercial | 380 | 344 | 361 | 440 | 439 |
| Industrial | 1,130 | 1,013 | 1,037 | 1,148 | 1,178 |
| Other | 518 | 428 | 422 | 362 | 389 |
| Total Heating | 121 | 108 | 110 | 112 | 121 |
| Non-Heating: | | | | | |
| Residential | 28 | 28 | 28 | 29 | 32 |
| CRP | 61 | 63 | 67 | (6) | 83 |
| Commercial | 294 | 296 | 289 | 314 | 335 |
| Industrial | 849 | 1,347 | 1,504 | 1,175 | 1,555 |
| Other | 901 | 682 | 617 | 772 | 666 |
| Total Non-Heating | 61 | 59 | 61 | 60 | 69 |
| Total Firm | 111 | 101 | 103 | 105 | 114 |
| Interruptible | 22,882 | 21,154 | 17,771 | 17,546 | 14,540 |
| Total Usage | 130 | 120 | 119 | 121 | 128 |

SOURCES: Pages 1 and 3 of Schedule 5.

**Philadelphia Gas Works**
**Annual Peak Day Supply**
**(Volumes in MMCF)**

| | 1996-1997 | 1997-1998 | 1998-1999 | 1999-2000 | 2000-2001 |
|---|---|---|---|---|---|
| Peak Day | 1/18/97 | 12/31/97 | 1/5/99 | 1/27/00 | 12/25/00 |
| Average Temp. (F) | 12 | 25 | 23 | 16 | 20 |
| Peak Firm Sendout | 619 | 449 | 503 | 583 | 515 |
| Total Sendout | 662 | 482 | 542 | 629 | 520 |
| Peak Day Supply Used | | | | | |
| Natural Gas | 434 | 361 | 449 | 444 | 397 |
| LNG | 228 | 121 | 93 | 185 | 123 |
| Total Supply | 662 | 482 | 542 | 629 | 520 |

SOURCE: Company's GCR Filing, Tab 11.

**Philadelphia Gas Works**
**Design Day Capacity**
**(MMCF)**

| | 2000-2001 | 2001-2002 | 2006-2007 |
|---|---|---|---|
| Transco | 219.0 | 225.6 | 225.6 |
| Texas Eastern | 227.3 | 234.1 | 229.1 |
| Total Available | 446.3 | 459.7 | 454.7 |
| LNG | 540.0 | 540.0 | 540.0 |
| Total Supply | 986.3 | 999.7 | 994.7 |
| Firm Demand | 783.4 | 789.7 | 821.7 |
| Supply Reserve | 202.9 | 210.0 | 173.0 |
| Reserve Percentage | 25.9% | 26.6% | 21.1% |
| LNG Design Requirement | 337.1 | 330.0 | 367.0 |
| LNG % of Capacity | 62.4% | 61.7% | 68.0% |

SOURCE: Company Response OCA 1-36 and Company Response OTS-RS-13.

**Philadelphia Gas Works**
**PGW's Annual Capacity Costs**
**($000's)**

| GCR Period | Amount | % Change | % Cumulative |
|---|---|---|---|
| 1995-1996 | $78,161 | - % | - % |
| 1996-1997 | 76,516 | (2.1) | (2.1) |
| 1997-1998 | 73,654 | (3.7) | (5.8) |
| 1998-1999 | 68,862 | (6.5) | (11.9) |
| 1999-2000 | 61,587 | (10.6) | (21.2) |
| 2000-2001 | 60,774 E | (1.3) | (22.2) |

SOURCE: Company Response OCA 1-4.

**Philadelphia Gas Works**
**Unaccounted for Gas Losses**
**(MMCF)**

| GCR Period | Firm Send-Out | Losses | Percentage | Five-Year Moving Avg. |
|---|---|---|---|---|
| 1990-1991 | 57,514 | 1,085 | 1.9% | - |
| 1991-1992 | 63,308 | 2,078 | 3.3% | - |
| 1992-1993 | 65,410 | 2,288 | 3.5% | - |
| 1993-1994 | 68,562 | 3,115 | 4.5% | - |
| 1994-1995 | 58,366 | 2,072 | 3.6% | 3.4% |
| 1995-1996 | 68,083 | 2,638 | 3.9% | 3.8% |
| 1996-1997 | 62,311 | 2,561 | 4.1% | 3.9% |
| 1997-1998 | 54,829 | 1,198 | 2.2% | 3.7% |
| 1998-1999 | 56,104 | 2,353 | 4.2% | 3.6% |
| 1999-2000 | 58,793 | 4,268 | 7.3% | 4.3% |
| 10 Year Average | 61,328 | 2,366 | 3.9% | - |

SOURCES: PGW 2000-2001 GCR Filing, Schedule SR3 and Response OTS 1-1.

**Philadelphia Gas Company**
**Annual Degree Days**

| GCR Period | Degree Days | % of Normal |
|---|---|---|
| 1993-1994 | 5,002 | 109.8 |
| 1994-1995 | 4,206 | 92.3 |
| 1995-1996 | 5,223 | 114.7 |
| 1996-1997 | 4,667 | 102.5 |
| 1997-1998 | 4,003 | 87.9 |
| 1998-1999 | 3,892 | 85.4 |
| 1999-2000 | 3,979 | 87.4 |
| 2000-2001 | 4,602 | 101.0 |
| 2001-2002 | 4,555 | 100.0 |

SOURCES: Previous Company GCR Filings and Company Response OCA 1-21, 2nd Quarter Update.

# Philadelphia Gas Works
# Base Rate vs. GCR Cost Recoveries

Gas Related Costs In Base Rates

- Rolled In Portion of Gas Costs (Currently $3.18 per MCF)
- LNG and Propane Facilities' Investment and Depreciation
- LNG and Propane Facilities' Operations and Maintenance Costs
- Margins on Interruptible Gas Sales

Non-Gas Related Costs In GCR Factor

- Conservation Works Program Costs
- Customer Responsibility Program (CRP) Costs
- Purchased Electricity and LNG Transportation Costs
- Senior Citizen Discounts
- Interim Settlement Bad Debt Expense

# VIII. APPENDIX: PRIOR R.W. LELASH TESTIMONIES

R. W. LELASH'S REGULATORY TESTIMONIES
(1997 to Present)

198. Georgia, Atlanta Gas Light (Docket No. 6717-U) Gas Service Unbundling Testimony for the Georgia Public Service Commission (January, 1997).

199. FERC, Cleveland Electric and Toledo Edison (Docket No. ER97-529-000, Consolidated) Rate of Return Rebuttal Testimony for Centerior Energy (April, 1997).

200. Rhode Island, Providence Gas Company (Docket No. 2581) Price Stabilization Plan Testimony for the Rhode Island Division of Public Utilities (August, 1997).

201. New Jersey, New Jersey Natural Gas Company (Docket No. GT96070524) Gas Policy Testimony for the New Jersey Division of the Ratepayer Advocate (August, 1997).

202. Vermont, Green Mountain Power Corporation (Docket No. 5983) Gas Remediation Recovery Testimony for the Vermont Department of Public Service (October, 1997).

203. Philadelphia Gas Commission, Philadelphia Gas Works (1998 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (December, 1997).

204. Vermont, Green Mountain Power Corporation (Docket No. 5983) Gas Remediation Surrebuttal Testimony for the Vermont Department of Public Service (December, 1997).

205. Delaware, Delmarva Power & Light Company (Docket No. 97-293F) Gas Price Hedging Testimony for the Delaware Public Service Commission (January, 1998).

206. Delaware, Artesian Water Company (Docket No. 97-340) Rate of Return Testimony for the Delaware Public Service Commission (February, 1998).

207. Georgia, Atlanta Gas Light Company (Docket No. 8390-U) Regulatory Policy Testimony for the Energy Service Providers Association (March, 1998).

208. New Jersey, Public Service Electric & Gas Company (Docket No. GR97110839) Gas Procurement and Policy Direct Testimony for the New Jersey Division of the Ratepayer Advocate (April, 1998).

209. New Jersey, Public Service Electric & Gas Company (Docket No. GR97110839) Gas Procurement and Policy Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (April, 1998).

210. Philadelphia Gas Commission, Philadelphia Gas Works (1998 GCR Proceeding) Gas Price Hedging Position Statement for the Public Advocate (May, 1998).

211. Philadelphia Gas Commission, Philadelphia Gas Works (1999 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (October, 1998).

212. Georgia, Cumberland Pipeline Investigation (Docket No. 10064-U) Regulatory Policy Testimony for East Tennessee Natural Gas Company (March, 1999).

213. New Jersey, Generic Unbundling Proceeding (Docket No. GX99030121) Gas Policy Testimony for the New Jersey Division of the Ratepayer Advocate (July, 1999).

214. New Jersey, Public Service Electric & Gas Company (Docket No. GO99030124) Gas Unbundling Testimony for the New Jersey Division of the Ratepayer Advocate (July, 1999).

215. Philadelphia Gas Commission, Philadelphia Gas Works (2000 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (September, 1999).

216. New Jersey, Generic Unbundling Proceeding (Docket No. GX99030121) Gas Policy Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (September, 1999).

217. New Jersey, Public Service Electric and Gas Company (Docket No. GO99030124) Gas Unbundling Surrebuttal Testimony for the New Jersey Division of the Ratepayer Advocate (September, 1999).

218. Pennsylvania, Columbia Gas of Pennsylvania, Inc. (Docket No. R-00994781) Restructuring Testimony for the Pennsylvania Office of Consumer Advocate (October, 1999).

219. Pennsylvania, Columbia Gas of Pennsylvania, Inc. (Docket No. R-00994781) Restructuring Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (October, 1999).

220. Rhode Island, Narragansett Electric Company et al. (Docket No. 2930) Merger Policy Testimony for the Rhode Island Department of Attorney General (November, 1999).

221. Delaware, Delmarva Power & Light Company (Docket No. 99-425F) Evaluation of Price Hedging Testimony for the Delaware Public Service Commission (December, 1999).

222. Rhode Island, Narragansett Electric Company et al. (Docket No. D-99-12) Merger Policy Testimony for the Rhode Island Department of Attorney General (December, 1999).

223. Pennsylvania, PECO Energy Company (Docket No. R-00994787) Restructuring Testimony for the Pennsylvania Office of Consumer Advocate (January, 2000).

224. Pennsylvania, PECO Energy Company (Docket No. R-00994787) Restructuring Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (February, 2000).

225. Rhode Island, Providence Gas Company and Southern Union (Docket No. D-00-3) Merger Policy Testimony for the Rhode Island Division of Public Utilities and Department of Attorney General (May, 2000).

226. Philadelphia Gas Commission, Philadelphia Gas Works (2001 GCR Proceeding) Gas Procurement and Policy Testimony for the Public Advocate (August, 2000).

227. Rhode Island, Providence Gas Company (Docket No. 2581) Price Stability Plan Testimony for the Rhode Island Division of Public Utilities (August, 2000).

228. Pennsylvania, Philadelphia Gas Works (Docket No. R-00005654) Interim Base Rate Testimony for the Pennsylvania Office of Consumer Advocate (September, 2000).

229. Pennsylvania, Philadelphia Gas Works (Docket No. R-00005619) Gas Procurement and Policy Testimony for the Pennsylvania Office of Consumer Advocate (September, 2000).

230. New Jersey, Generic Provisional Rate Proceeding (Docket Nos. GR00070491, et al.) Provisional Rate Statement for the New Jersey Division of the Ratepayer Advocate (October, 2000).

231. New Jersey, Public Service Electric & Gas Company (Docket No. GR00070491) Levelized Gas Adjustment Clause Testimony for the New Jersey Division of the Ratepayer Advocate (November, 2000).

232. New Jersey, Generic Provisional Rate Proceeding (Docket Nos. GR00070491, et al.) Provisional Rate and Price Hedging Testimony for the New Jersey Division of the Ratepayer Advocate (December, 2000).

233. Rhode Island, Providence and Valley Gas Companies (Docket Nos. 1673 and 1736) Gas Price Mitigation Testimony for the Rhode Island Division of Public Utilities (January, 2001).

234. Delaware, Delmarva Power & Light Company (Docket No. 00-463F) Gas Price Hedging Testimony for the Delaware Public Service Commission (February, 2001).

235. Pennsylvania, Philadelphia Gas Works (Docket No. R-00006042) Base Rate and Policy Testimony for the Pennsylvania Office of Consumer Advocate (April, 2001).

236. Pennsylvania, Philadelphia Gas Works (Docket No. R-00006042) Base Rate and Policy Surrebuttal Testimony for the Pennsylvania Office of Consumer Advocate (May, 2001).

237. New Jersey, Public Service Electric & Gas Company (Docket No. GM00080564) Capacity Contract Transfer Testimony for the New Jersey Division of the Ratepayer Advocate (June, 2001).

238. Vermont, Vermont Gas Systems (Docket No. 6495) Rate Stabilization Plan Testimony for the Vermont Department of Public Service (June, 2001).

OCA Statement No. 1-S

8/8/01
Phila DD
RJS

BEFORE THE PENNSYLVANIA
PUBLIC UTILITY COMMISSION
DOCKET NO. R-00016378

IN THE MATTER OF THE FILING OF
PHILADELPHIA GAS WORKS
CONCERNING ITS
2001-2002 GAS COST RATE

SURREBUTTAL TESTIMONY OF
RICHARD W. LELASH
ON BEHALF OF THE
OFFICE OF CONSUMER ADVOCATE







AUGUST, 2001

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Richard W. LeLash, and my business address is 18 Seventy Acre Road, Redding, Connecticut.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, I previously submitted direct testimony which has been identified as OCA Statement No. 1.

Q. WOULD YOU PLEASE STATE THE SCOPE AND PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. In this testimony, I will address the Company's Revised 2001-2002 GCR calculation which was sent to the parties on July 16, 2001. My testimony will also address various issues which were discussed by Mr. White in his filed rebuttal testimony.

Projected GCR Rate

Q. IN MR. WHITE'S REBUTTAL TESTIMONY DID HE DEVELOP AN UPDATED GCR FACTOR FOR 2001-2002?

A. No, it appears that he did not. While Mr. White discusses the GCR factor which would be associated with his updated gas cost estimates, he also states that this is not necessarily the Company's final position, and he implies that the Company will consider whether or not to "supplement" the record prior to the close of the record in this proceeding.

Absent any GCR calculation submitted by the Company, I have developed a comparison between the Company's position in its initial filing and its calculation as modified for the July updates. This comparison is shown on Schedule 1-S. Based on the gas cost updates and some related changes, the filed GCR factor of $5.5958 per Mcf should be reduced to $3.0542 per Mcf. This reflects a $141.6 million overall reduction to the Net Applicable GCR Expense.

In addition to the adjustment for lower wholesale natural gas costs, the Company's updated calculations also reduced the CRP Discounts by $7.8 million and the Prior Year Reconciliation by $15.8 million. These reductions, along with the reduction of gas costs of $118.0 million, are the basis for the overall $141.6 million reduction.

Q. DO YOU BELIEVE THAT THE UPDATED GCR CALCULATION IS REASONABLE AND THAT IT SHOULD BE USED FOR ESTABLISHING THE GCR FACTOR FOR 2001-2002?

A. Yes, I do. While Mr. White has stated that gas prices have increased since the update was developed, gas prices have actually fluctuated. However, while they were somewhat higher in mid-July, as of the end of July the updated calculations are compatible with the prevailing futures prices and the latest DRI forecast.

On the first page of Schedule 2-S data is provided for a comparison of various DRI forecasts. As shown, the DRI forecast has increased slightly from the average updated level of $3.18 per Dth to the most current average forecasted level of $3.26 per Dth. A similar comparison for the NYMEX pricing is shown on the second page of the schedule. In the update, which utilized the June 29 NYMEX Henry Hub prices, the average was $3.52 per Dth. As the other July data shows, the average price did increase around July 11, but as of July 27 it has returned to a level which is comparable to that utilized in the Company's update.

On page 3 of Schedule 2-S the two components which formed the basis for the Company's update are averaged. The DRI forecast from mid-July and the NYMEX prices as of July 27 average $3.42 per Dth when combined. Therefore, these two indicators of prospective wholesale gas costs continue to affirm the average FY 2001-2002 price of $3.42 per Dth which was incorporated into the Company's updated GCR calculation.

Using the Company's average derived costs also results in the downward adjustments for the CRP discounts and the deferred gas cost balance. These reductions appear commensurate with the gas cost decreases, and therefore, I believe the Company's updated estimates are reasonable.

Q. COULD CHANGES IN THE WHOLESALE LEVEL OF GAS PRICES MODIFY THE UPDATED GCR CALCULATION?

A. Yes, but it is necessary to be pragmatic at this point in time. The actual gas costs for FY 2001-2002 will not be known until September 2002. At some point in time, the updating process has to end and the Commission needs to set a GCR factor. To the degree there is a reversal in the wholesale natural gas price trend, PGW will be able to update its GCR factor at the time it makes its compliance filing on December 1 -- before the majority of the winter sales are made. Furthermore, under the Commission's regulations and the Company's tariff, the Company is required to update its GCR factor if its quarterly reconciliation differs from the currently effective rate by more than 2 percent. Accordingly, the Company should update its GCR calculation (as shown in the right column on Schedule 1-S) and implement the $3.0542 factor as a quarterly update effective September 1.

<u>LNG Transportation Costs</u>

Q. WOULD YOU PLEASE DISCUSS MR. WHITE'S OBSERVATIONS CONCERNING ITS RECOVERY OF LNG TRANSPORTATION COSTS?

A. Mr. White claims that these costs are includable in natural gas costs by virtue of the Gas Choice Act. The relevant issue, however, is whether or not such costs were validly included within the prior years' reconciliations. The LNG Transportation Costs at issue were incurred during fiscal years 1998-1999 and 1999-2000, during the period when

PGW's GCR was set by the Philadelphia Gas Commission ("PGC"). These costs continue to be recovered as part of the deferred fuel balance in the FY2002 GCR.

Q. IS THERE ANY WAY TO DETERMINE WHETHER OR NOT THE PHILADELPHIA GAS COMMISSION SPECIFICALLY AUTHORIZED RECOVERY THROUGH THE GCR MECHANISM?

A. Yes, there is. In the FY 1999-2000 GCR proceeding, PGW requested the Philadelphia Gas Commission to start permitting LNG Transportation expenses to be included within the GCR. However, the Hearing Examiner recommended that such expenses not be allowed as a new applicable fuel expense (Recommended Decision, PGW FY 2000 GCR, October 27, 1999, pp. 18-20). To the best of my knowledge, the Philadelphia Gas Commission did not subsequently approve the Company's request.

Accordingly, PGW was not authorized to recover LNG Transportation Costs within the GCR, and thus, there should be a reduction to its deferred fuel balance of $170,000 to reflect the improperly calculated reconciliations.

Gas Cost Credits

Q. IN MR. WHITE'S REBUTTAL TESTIMONY HE RAISES ISSUES CONCERNING YOUR ADJUSTMENTS FOR CAPACITY RELEASE AND OFF-SYSTEM SALES. DO YOU HAVE ANY COMMENTS CONCERNING HIS TESTIMONY?

A. With respect to Off-System Sales, Mr. White reiterates the Company's position that such sales are speculative. While I agree that the sales are variable, it is obviously incorrect to continue to assume, as the Company has done, that no sales will be made. The simple fact is that such off-system sales have generated about $2.3 million in average annual credits to the cost of gas during the past two years. Accordingly, a $2.0 million credit for the upcoming year is a reasonable estimate.

Q. MR. WHITE ALSO COMMENTS ON YOUR CAPACITY RELEASE ESTIMATE. AGAIN, DO YOU HAVE ANY COMMENTS?

A. Mr. White claims that, with natural gas prices declining, there will be reduced demand. Accepted economic theory, however, would indicate that falling prices will increase rather than decrease demand. Furthermore, with increased demand from electric generation and the removal of price caps on capacity releases by FERC, there may be additional opportunities available for natural gas distribution companies to generate additional capacity release revenues from unutilized capacity. Accordingly, my recommended capacity release credits, which are based on recent results including 2000-2001 when gas prices were at very high levels and demand in the capacity release market was low, are conservative and reasonable.

<u>Risk Management Strategy</u>

Q. IN HIS REBUTTAL TESTIMONY, MR. WHITE STATES THERE IS NO NEED FOR FURTHER PUC ACTION OR APPROVAL OF THE COMPANY'S RISK MANAGEMENT PROGRAM. DO YOU AGREE?

A. I agree that if PGW does not pursue a reasonable risk management program in the future by utilizing an appropriate level of gas price hedging, it will be subject to PUC review. My direct testimony merely intended to have the Company address certain gaps in its program. For example, its hedging program does not currently include the use of financial (vs. physical) hedge positions. Most gas utilities incorporate financial hedging as part of a portfolio approach for gas supply procurement. By including such a component, the gas utilities also clarify whether or not hedging costs associated with such transactions can be treated as recoverable gas costs. PGW should assess whether it should utilize financial hedge positions as part of its overall risk management strategy.

A review of PGW's current Risk Management Policy, which is attached to Mr. White's rebuttal testimony, also shows other program parameters which are not specified. Many such policy statements specify such things as who must authorize hedge positions, what minimum and maximum percentage of normalized purchases will be hedged, what basic guidelines are used to determine when and if a hedged position will be taken, and a description of hedging strategies for summer vs. winter purchase requirements. It has been my experience that by specifying such hedging parameters, the gas utilities and their regulators have a better understanding of the program and more objective program reviews are possible because all parties have common perceptions of what the program intends to accomplish. On this basis, I still do not believe that PGW has adequately defined its "objectives and procedures for its on-going gas price hedging, including the scope, control, and financial exposure aspects of its prospective hedging initiatives."

<u>General GCR Issues</u>

Q. DO YOU HAVE ANY OTHER COMMENTS CONCERNING MR. WHITE'S REBUTTAL TESTIMONY?

A. Yes, there are three other matters which need clarification based on Mr. White's comments. The first involves the authorization process for gas supply contracts. While I understand that PGW has operated without appropriate approvals for some time, I disagree that this fact is irrelevant to this proceeding. In the competitive gas supply market there is increasing concern over supply reliability. However, generally in supply contracts there are provisions and penalties for non-performance by a supplier which provide the supplier with an economic incentive to perform. My concern is that, if a gas supply agreement has not been duly authorized and signed, PGW's right to enforce applicable contract provisions may be impaired. This matter has also been an on-going concern of PGW based on its response to discovery. (OCA-I-14). Accordingly, I still believe that the issue should be resolved in a timely manner.

The second matter involves the Company's LNG capacity. In the past the Company has planned its supply under the assumption that it had 450 MMcf of vaporization capacity at Richmond and 90 MMcf of capacity at Passyunk. These were the assumptions as recently as June 9, 2000 when the Company developed its Design Day analysis. Now in Mr. White's current rebuttal testimony it is stated that the combined LNG vaporization capacity has declined to a level of 395 MMcf. This represents a 27% reduction in the Company's peak day supply. On this basis, it is understandable that Mr. White claims far lower peak day reserve capacity. However, it obviously raises the question of what happened to 145 MMcf of peak day LNG capacity. According to the Company's Response to OTS 1-10, the 395 MMcf capacity is not related to the current LNG upgrade, but rather it is the new vaporization capacity assumption through 2007.

On Schedule 3-S, the design day capacity is shown in MMcf for the 2001-2002 GCR period. The column designated "Old" contains the previous maximum daily vaporization rate of 540 MMcf, while the data designated "New" contains the Company's claimed effective daily vaporization rate of 395 MMcf. As shown, the effect on the measurement of the peak day capacity reserve is material. What is shown to be a 26.3% reserve with the previous vaporization capacity, becomes only a 7.7% reserve under the Company's revised capacity definition.

Accordingly, it is recommended that the PUC require PGW to provide a detailed explanation of why the LNG facilities have apparently lost a material amount of their daily vaporization and, as a corollary, a proportionate amount of their operational and economic value.

The third matter involves the measurement of the Company's Unaccounted For Gas ("UFG"). Accepting Mr. White's contention that the 1999-2000 UFG loss was 6.3%, there is still reason for concern. While Mr. White agrees that unbilled revenues account for some of the increase, his UFG percentage, when adjusted for unbilled revenues, is still a relatively high 5.2%. In addition, it is unclear that the unbilled sales from 1999-2000 will be billed during 2000-2001. There have been problems with the Company's billing system, and it seems entirely possible that some of these unbilled sales will not be billed in the future.

Thus, there should be a continuing concern as to why the UFG percentage which has typically been between 3.4% and 3.9% should now be averaging 4.2% and may be, in certain years, as high as 5.2%. Accordingly, it still seems necessary for the Company "to determine why the level of unaccounted for gas losses continues to rise."

Q. MR. LELASH, DOES THAT CONCLUDE YOUR SURREBUTTAL TESTIMONY IN THIS MATTER?

A. Yes, it does.

*64968

## Supporting Schedules

**Philadelphia Gas Works**
**2001-2002 GCR Factor**
**(000's)**

| | As Filed | Difference | Updated |
|---|---|---|---|
| Applicable Sales Volume | 57,889 | 614 | 58,503 |
| Expenses - Fuel | | | |
| Total Applicable Fuel Expense | $456,486 | $(117,990) | $338,496 |
| Expenses - Non-Fuel | | | |
| Conservation Programs | $ 2,200 | $ - | $ 2,200 |
| CRP Discounts | 37,696 | (7,761) | 29,935 |
| Total Applicable Non-Fuel Expense | $ 39,896 | $ (7,761) | $ 32,135 |
| Applicable GCR Expense | $496,382 | $(125,751) | $370,631 |
| Adjustment For: | | | |
| Gas Refunds | $ 0 | $ - | $ 0 |
| Prior Year Reconciliation | 12,375 | (15,832) | (3,457) |
| Total Adjustment | $ 12,375 | $ (15,832) | $ (3,457) |
| Net Applicable GCR Expense | $508,757 | $(141,583) | $367,174 |
| Applicable Unit GCR Expense | $ 8.7886 | $ - | $ 6.2762 |
| Base Fuel Cost Recovery | 3.1800 | | 3.1800 |
| Applicable GCR Factor (per MCF) | $ 5.5958 | $ (2.5416) | $ 3.0542 |

SOURCES: OCA Statement No. 1 and Updated Item 53.64, Sheet 1.

**Philadelphia Gas Works**
**Comparative DRI Forecasts**
**Henry Hub Per Dth**

| | Filed DRI | June DRI | Updated DRI | July DRI |
|---|---|---|---|---|
| September 2001 | $6.11 | $3.50 | $2.88 | $2.80 |
| October | 6.25 | 3.72 | 2.79 | 2.75 |
| November | 6.41 | 4.00 | 2.75 | 3.10 |
| December | 6.56 | 4.24 | 3.07 | 3.30 |
| January 2002 | 5.67 | 4.34 | 3.30 | 3.45 |
| February | 5.17 | 4.31 | 3.25 | 3.58 |
| March | 5.08 | 4.13 | 3.15 | 3.37 |
| April | 5.37 | 3.73 | 3.20 | 3.31 |
| May | 5.54 | 3.66 | 3.30 | 3.30 |
| June | 5.65 | 3.70 | 3.40 | 3.35 |
| July | 5.51 | 3.74 | 3.50 | 3.40 |
| August | 5.41 | 3.76 | 3.60 | 3.43 |
| Averages | $5.73 | $3.90 | $3.18 | $3.26 |

SOURCES: Company Supplied Data and Monthly DRI-WEFA Monthly Natural Gas Price Outlooks.

**Philadelphia Gas Works**
**Comparative NYMEX Prices**
**Henry Hub Per Dth**

| | June 29 | July 11 | July 20 | July 27 |
|---|---|---|---|---|
| September 2001 | $3.17 | $3.41 | $3.00 | $3.19 |
| October | 3.26 | 3.49 | 3.05 | 3.24 |
| November | 3.54 | 3.74 | 3.32 | 3.50 |
| December | 3.82 | 3.99 | 3.60 | 3.76 |
| January 2002 | 3.90 | 4.09 | 3.71 | 3.86 |
| February | 3.80 | 4.00 | 3.65 | 3.80 |
| March | 3.63 | 3.85 | 3.53 | 3.70 |
| April | 3.38 | 3.62 | 3.36 | 3.54 |
| May | 3.36 | 3.62 | 3.37 | 3.56 |
| June | 3.41 | 3.67 | 3.41 | 3.60 |
| July | 3.46 | 3.72 | 3.46 | 3.64 |
| August | 3.48 | 3.75 | 3.48 | 3.67 |
| Averages | $3.52 | $3.75 | $3.41 | $3.58 |

**Philadelphia Gas Works**
**Comparison of Price Assumptions**
**Henry Hub Per Dth**

| | Update | DRI | NYMEX | Average |
|---|---|---|---|---|
| September 2001 | $3.17 | $2.80 | $3.19 | $3.00 |
| October | 3.26 | 2.75 | 3.24 | 3.00 |
| November | 3.54 | 3.10 | 3.50 | 3.30 |
| December | 3.82 | 3.30 | 3.76 | 3.53 |
| January 2002 | 3.90 | 3.45 | 3.86 | 3.65 |
| February | 3.25 | 3.58 | 3.80 | 3.69 |
| March | 3.15 | 3.37 | 3.70 | 3.54 |
| April | 3.20 | 3.31 | 3.54 | 3.42 |
| May | 3.30 | 3.30 | 3.56 | 3.43 |
| June | 3.40 | 3.35 | 3.60 | 3.47 |
| July | 3.50 | 3.40 | 3.64 | 3.52 |
| August | 3.60 | 3.43 | 3.67 | 3.55 |
| Averages | $3.42 | $3.26 | $3.58 | $3.42 |

SOURCE: Company Supplied Data and Schedule S-2, pages 1 and 2.

**Philadelphia Gas Works**
**Design Day Capacity**
**(2001-2002 MMcf)**

| | Old | New |
|---|---|---|
| Transco | 219.0 | 219.0 |
| Texas Eastern | 227.3 | 227.3 |
| Total Pipeline | 446.3 | 446.3 |
| LNG | 540.0 | 395.0 |
| Total Supply | 986.3 | 841.3 |
| Firm Demand | 780.8 | 780.8 |
| Supply Reserve | 205.5 | 60.5 |
| Reserve Percentage | 26.3% | 7.7% |
| LNG Design Requirement | 334.5 | 334.5 |
| LNG % of Capacity | 61.9% | 84.7% |

SOURCE: White Rebuttal Testimony, Exhibit CW R-2.