BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

VOLUME II

TESTIMONY
and EXHIBITS

ON BEHALF OF
PHILADELPHIA GAS WORKS

PHILADELPHIA GAS WORKS

R-2009-2139884

DECEMBER 2009

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PGW St. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

STEVEN P. HERSHEY

ON BEHALF OF

PHILADELPHIA GAS WORKS

DOCKET No. R-2009-2139884

December 2009

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND POSITION WITH THE COMPANY.

A. I am Steven P. Hershey. My title is Vice President - Regulatory and External Affairs.

Q. HOW LONG HAVE YOU HELD THIS POSITION?

A. I was promoted to this position in January, 2006.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I have been employed with PGW since January, 2004. Prior to that, I was an attorney at Community Legal Services from 1976 to 1998. During that time I served as the Public Advocate, representing PGW's residential customers, from 1986 to 1998. I practiced law, specializing in energy and utility matters, at the firm of Eckert Seamans Cherin & Mellott from 1998 through December, 2003.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I earned my B.A. from Hamilton College in 1966 and a law degree from Georgetown University Law Center in 1969.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes, I testified before this Commission in PGW's last base rate case, Docket No. R-00061931, which was filed in 2006.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. The purpose of my testimony is to provide an overview and roadmap of PGW's filing, including a summary of the reasons for the increase, and a summary of the testimony to be presented by other witnesses. I will also explain PGW's proposal to help customers save money and conserve energy by implementing a multi-year Demand-Side Management and Conservation ("DSM") program.

II. OVERVIEW OF REASONS FOR RATE FILING

Q. WHY HAS PGW MADE THIS FILING?

A. PGW has filed this case for three main reasons. First, in the PUC's December, 2008 order authorizing a $60 million extraordinary rate increase, PGW was directed to file a general rate case by the end of 2009. This filing satisfies that requirement. Second, as shown in the testimony of Mr. Bogdonavage, Mr. Hanley and Ms. Bisgaier, PGW has submitted the financial justification necessary to show that the $60 million rate increase that the Commission authorized in the Extraordinary Rate proceeding continues to be just and reasonable and crucially necessary for PGW to be able to complete several key financial transactions in the upcoming months and maintain its marginally acceptable bond rating. Third, as explained below, PGW is requesting a rate increase in order to fund its current post-employment benefit liability.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT THAT PGW BE PERMITTED TO MAINTAIN ITS CURRENT RATE LEVELS.

A. It is very important that the Commission continue to permit PGW to have the resources to operate as a going concern and continue to be able to access capital markets, and thus continue to be able to finance its annual capital improvements. This will allow the Company to continue to provide safe and adequate service. As described in detail by Mr. Bogdonavage, PGW has experienced a significant increase in non-gas operating expenses and interest expense since its last fully litigated case. It is imperative that PGW at least maintain its current rate level, including the $60 million awarded in the Extraordinary Rate Order, so that PGW: (1) will maintain its key financial indices at appropriate levels; (2) assure that its bond rating at least does not drop below investment-grade; (3) assure that it successfully renews its short term borrowing facility; and (4) is able to sell bonds to finance its capital program.

As Ms. Bisgaier explains, PGW must have adequate liquidity, when needed, without having to resort solely to borrowing. PGW must break the ever-more expensive cycle of cash deficits which require one-time fixes and even more borrowing. PGW is billing approximately $800 million in revenues and yet, until this past year, had no internally generated funds since the mid- 90's. The Company has limped from one crisis to the next, never having the resources to address its structural financial problems. In the last few years, PGW has found itself with only the slimmest of available cash balances – in one instance just $4 million after paying a winter gas bill – and all of it from borrowed funds. PGW cannot survive unless it is able to borrow, but, borrowing has only pushed PGW and its customers deeper into the hole.

The Commission's action last December, in awarding PGW a $60 million extraordinary rate increase, was enormously helpful. It provided PGW with the ability to avoid a series of financial crises brought on by the recession and credit crisis that had exacerbated an already precarious financial condition. It is important to maintain the forward motion that has resulted from the Commission's action. PGW has several key financial hurdles still to face and any backtracking would place the Company in severe jeopardy of not being able to complete those remaining tasks. Also, as Ms. Bisgaier points out, were there to be an actual reduction in PGW's existing rate level, the Company would be at a significant risk of being downgraded below investment quality. Since PGW is already anticipating that it will have a difficult time selling bonds in October of 2010 (most likely without bond insurance) such a step backward would be a disaster for the Company and its customers. Indeed, PGW's proposal here is designed to resolve an issue that, if addressed, will put the Company in a position to see its bond rating improve – the funding of PGW's significant OPEB liability. I discuss this proposal below.

Q. PLEASE EXPLAIN THE BASIS FOR PGW'S RATE INCREASE REQUEST.

A. As indicated, the third reason for the filing, and the basis for the proposed rate increase, is to provide funding for PGW's Other Post-Employment Benefits (OPEB) liability. As described in detail by Mr. Bogdonavage and Mr. Kikla, due to changes in accounting standards it is necessary to fund PGW's obligations with regard to post-employment health care and life insurance. Just as investor-owned utilities have done in the mid-1990's, PGW proposes to fund this obligation through rates. Projected funding will be at an initial level of $42.5 million that will then decline to $39 million in 2011, $35.5 million in 2012, $32 million in 2013, $28 million in 2014 and $7 million in 2015. To recognize these reductions in liability, it is further proposed that there be annual rate adjustments for what are revised actuarial projections for each period. These changes are shown in Mr. Kikla's analysis and incorporate the benefits achieved from directing dollars to an irrevocable "trust" for investment.

Q. PLEASE SUMMARIZE PGW'S CLAIM FOR OTHER POST EMPLOYMENT BENEFITS.

A. As explained in detail by Mr. Bogdonavage and Mr. Kikla, PGW now pays for these post employment benefits on a pay as you go basis each year. PGW is required by the Government Accounting Standards Board ("GASB") to switch to an accrual method of accounting for these expenses and has done so. On an actuarial basis, however, PGW has a large, $653 million, liability at the end of the test year. At present, PGW has not funded any of this liability and the annual accrual creates a large, continuing drain on PGW's earnings. PGW's debt-to-total capitalization ratio continues to deteriorate. The liability is impeding any opportunity for improvement in PGW's bond rating and creates an additional risk that will be considered by any potential purchasers of PGW securities. As demonstrated by Mr. Kikla, funding these obligations in the manner proposed in this proceeding would save customers approximately $200 million over thirty years (reducing the present value liability to approximately $455 million). In addition, such a provision will maintain a predictable source of funding to protect the rights of workers and retirees. As Ms. Bisgaier explains, funding this OPEB liability will have a salutary affect on PGW's capital structure, reduce the perceived risk that the company will not be able to satisfy this substantial liability in the future, and eliminate a central reason why PGW's one-level-above-non-investment grade, bond rating doesn't improve.

III. DEMAND SIDE MANAGEMENT PROPOSAL

Q. PLEASE EXPLAIN WHY PGW HAS PROPOSED A DEMAND SIDE MANAGEMENT PROGRAM BEYOND THE MANDATED LOW INCOME PROGRAM CURRENTLY OFFERED.

A. As described by Ms. Coltro, PGW has offered a low-income weatherization program, called the Conservation Works Program or CWP, since 1990. That program has served participants in the low-income Customer Responsibility Program ("CRP") and has been demonstrated through independent audits and PUC review to be cost-effective. PGW believes that all customers could benefit from a dramatic expansion of PGW's conservation efforts and that it is appropriate to do so. As a result, earlier this year PGW sought Commission approval of a program that significantly expands the current conservation program. PGW is now transferring that proposal to this case.

Q. WHY DO YOU BELIEVE THAT IT IS APPROPRIATE?

A. Energy efficiency and reduction of green house gases is now the articulated policy of this Commission and the governments of the City of Philadelphia, the Commonwealth of Pennsylvania and the United States. This comprehensive position should be reason enough, but there are additional reasons. As cited by Mr. Plunkett, we know that utility-sponsored energy efficiency programs are effective in reducing fuel consumption and that they benefit the customers with lower bills and the environment with a reduced carbon footprint. Such programs also create jobs in the local economy. PGW's proposed program, as designed, will result in this array of benefits.

Q. ARE THERE COSTS THAT RATEPAYERS WILL HAVE TO PAY IN ORDER TO BE ABLE TO IMPLEMENT THIS PROGRAM?

A. Yes, but this program, as demonstrated by Mr. Plunkett and Mr. Chernick, will be cost effective, will have immediate benefit for the customers treated under the program and will begin providing benefits for all customers on a very reasonable schedule. There is no argument that this kind of program, which will reduce the consumption of so many who cannot now afford their bills, will be a good investment. Overall, the witnesses calculate that the benefits will outweigh the costs by a factor of two to one.

PGW would like to offer a program that is robust. In order to facilitate a program launch, the emphasis in the early stages of the effort will be on the expansion of PGW's existing low income Conservation Works Program.

Q. PLEASE DESCRIBE PGW'S DSM PROPOSAL.

A. Management began planning this initiative during the summer of 2008. Subsequently, at the time of the Extraordinary Rate filing, we committed to filing a conservation program as part of a long term effort to create value for our customers and the City and to reduce PGW's business and financial risks. As explained by Mr. Plunkett, PGW's commitment is to reduce customer consumption of natural gas in order to achieve savings and benefits for the customer, for the economy and for the environment.

That commitment is only qualified to the extent such reduced consumption erodes PGW's ability to provide the reliability and safety required to serve our customers. As explained in the testimony of Mr. Chernick, the program will reduce PGW commodity and storage costs and thereby improve cash flow and reduce reliance on borrowing. This cost reduction will, after an initial period, outweigh the cost of the program, enabling PGW to reduce costs for customers. This proposal also provides means for the Company to maintain margin lost by reductions in sales as customers conserve.

The proposed expanded plan is composed of seven separate programs, each designed for a different segment of the customer base and each to be implemented according to a schedule described by Mr. Plunkett. PGW proposes to spend approximately $54 million over five years. This investment would:

- yield savings to all customers of approximately $113 million in today's dollars;
- save 1,321 billion BTU;
- reach 88,600 customers directly;
- substantially reduce greenhouse gas emissions such as carbon dioxide by one million tons;
- create 600 to 1,000 new jobs.

The largest program in this proposal is a program for low income customers. This is the program that is first to be implemented, followed by the non-low-income residential program. The other programs, described in Mr. Plunkett's testimony are:

- Premium efficiency gas appliance and heating equipment;
- Commercial and industrial equipment efficiency upgrades;
- Municipal facilities comprehensive efficiency retrofit;
- High efficiency construction;
- Commercial and industrial retrofit.

Q. WHY HAS PGW PROPOSED COST RECOVERY?

A. PGW is asking that the Commission allow PGW to implement an automatic adjustment clause that would permit full recovery of costs – the cost of implementing the program as well as the non-gas revenues lost as a direct result of the measures installed under this program.

Both Mr. Bogdonavage and Ms. Bisgaier demonstrate in their testimony that, financially, PGW is in no position to absorb either the cost of implementing the proposed DSM plan or any significant portion of the revenue lost as a direct result of such implementation. Even without a DSM program, PGW sales, like that of most other gas utilities, have declined steadily over the last 25 years and it is anticipated that the trend will continue as equipment available in the market becomes more efficient than models being replaced in the ordinary course. The result is that PGW must spread costs of operation over an ever shrinking sales base . Implementation of a conservation program, which would exacerbate that problem, is not feasible for PGW without cost recovery.

Moreover, if PGW did not implement a specific charge to recover the costs of the DSM program, customers would still pay for it – only indirectly through future rate requests to provide sufficient revenues to meet its required financial metrics and revenue requirement. PGW's proposed clause would allocate the costs in an appropriate manner, assigning those costs to the rate class that receives the benefit, except for the low income portion of the program, which appropriately assigns the cost to all firm ratepayers.

This DSM proposal, if approved by the PUC, can satisfy both broad public policy objectives and enhance PGW's ability to provide cost effective service.

Q. WHY IS PGW PROPOSING TO ADDRESS THIS PROPOSAL IN THE RATE CASE?

A. The DSM program will have a direct financial impact on PGW and should, when possible, be reviewed with other rate-related issues. Since it is important that the DSM program be implemented as quickly as possible to provide the benefits described above, PGW will ask this Commission to review and order implementation of the low-income segment of the DSM plan on an expedited basis. Inclusion in the rate case also provides the opportunity to set the proper base of *pro forma* revenues by which to measure changes in revenues due to the DSM program.

IV. <u>SUMMARY OF FILING</u>

Q. PLEASE INDICATE WHO THE WITNESSES WILL BE FOR PGW IN THIS PROCEEDING AND THEIR RESPONSIBILITIES FOR THE FILING?

A. PGW's witnesses and a summary of their testimony are as follows:

- Mr. Joseph Bogdonavage (PGW Statement 2) is Senior Vice President - Finance. Mr. Bogdonavage provides the financial details that support the need for the rate increase, shows the consequences of a failure to provide rate relief and displays PGW's financial results if it is granted the rate relief requested.

- Ms. Barbara Bisgaier (PGW Statement 3) is a Managing Director of Public Financial Management, Inc. She has been PGW's financial advisor for 14 years and is a Financial Advisor to the Commonwealth of Pennsylvania and to the City of Philadelphia. She is familiar both with PGW's history and the initiatives undertaken by this management to rebuild the utility. She is an expert on financial markets and financial instruments. Ms Bisgaier testifies to the level of financial performance required to complete successfully the continuing essential financial transactions and to maintain PGW's investment grade bond rating.
- Mr. Samuel Kikla (Statement 4), PGW's actuary, explains PGW's OPEB obligations and proposal in detail.
- Mr. Ken Dybalski (Statement 5), Director of Gas Planning at PGW, presents the proof of revenue, describes PGW's proposal for allocation of the rate increase, explains the proposed "Efficiency Cost Recovery Mechanism," describes two minor proposed tariff changes and explains the results of PGW's review of the level of gas supply-related costs in base rates.
- Mr. Randy Gyory (Statement 6), Senior Vice President for Operations and Customer Affairs, addresses certain tariff changes proposed by PGW.
- Ms. Cristina Coltro (Statement 7), Vice President, Customer Affairs describes PGW's existing universal service programs and provides data on cost offsets related to CRP requested by the PUC.
- Mr. Howard Gorman (Statement 8) is a Principal Consultant with R.J. Rudden Associates, a unit of Enterprise Management Solutions Black & Veatch Corporation. Mr. Gorman testifies to the unbundled, fully allocated class cost of

service study that he performed as well as the assignment of the total costs and other elements of the revenue requirements of the Company to each Rate Class. The Cost of Service Study is Volume III of the Filing. In addition to these statements, PGW is submitting data required by the PUC's filing requirements (Volume IV) and its Tariff Supplement No. 36, (Volume I) which sets forth all of the changes and rate increases proposed by PGW as part of this case.

- Mr. Frank Hanley (Statement 9) a Principal of Associated Utility Services ("AUS"), discusses the results of a "comparable" financial metric study which PGW commissioned that demonstrates the need to maintain PGW's existing rates and grant PGW's proposed rate increase.
- Mr. John Plunkett (Statement 10), is a partner in and president of Green Energy Economics Group, Inc., and has testified on a range of energy and utility matters and advised clients, including consumer advocates, on DSM program design, among other matters. He sponsors the DSM Plan and provides supporting detail and documentation.
- Mr. Paul Chernick (Statement 11), is president of Resource Insight, and has advised numerous clients, including consumer advocates, on issues related to program design and cost recovery related to DSM programs, as well as other utility and energy matters. He addresses cost recovery issues related to the DSM Plan.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

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PGW St. No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

JOSEPH R. BOGDONAVAGE

ON BEHALF OF
PHILADELPHIA GAS WORKS
DOCKET No. R-2009-2139884

December 2009

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND POSITION WITH THE COMPANY.

A. My name is Joseph R. Bogdonavage. My position is Senior Vice President - Finance.

Q. HOW LONG HAVE YOU HELD THIS POSITION?

A. I was promoted to this position in December 2000.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I have been employed with PGW since 1973, during which time I have held various positions in the Finance area. I most recently held the position of Director – Budget & Financial Forecasting.

Q. PLEASE SUMMARIZE YOUR PRINCIPAL RESPONSIBILITIES AS SENIOR VICE PRESIDENT- FINANCE.

A. My principal responsibilities include the oversight of PGW's Accounting & Reporting, Budget & Financial Forecasting, Treasury, and Procurement & Contract Services Departments. I am currently responsible for the overall preparation of the Operating and Capital Budgets, review of operating budgets prepared by the individual departments, and the coordination, analysis issuance and overall control of the complete annual Operating Budget filing. These activities include the preparation of analyses for the purposes of generating financial data to support the company's financial planning and decision-making processes. In addition, documentation is prepared regarding financial initiatives; i.e., proposed revenue bonds, commercial paper program offerings and base rate case presentations. Finally, in coordination with the Controller, the Budget area acts as a liaison between all departmental budget representatives regarding budgeting and financial forecasting procedures and variances analysis reporting.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor's Degree in Accounting from Temple University in 1972.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes, I testified before the Pennsylvania Public Utility Commission ("PUC") in conjunction with PGW's 2001 base rate case (R-00006042), its 2002 base rate case (including its request for extraordinary rates) (R-00017034), its 2003 Restructuring Proceeding (M-00021612), the 2004 Consolidated Proceeding (P-00042090) the 2006-07 base rate proceeding (R-00061931) and the 2008 request for extraordinary/emergency rates (R-2008-2073938). I have also testified before the Philadelphia Gas Commission ("PGC") on numerous occasions, most recently on matters associated with PGW's FY 2010 Operating Budget.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THESE PROCEEDINGS?

A. The purpose of my testimony is to: 1) provide the documentation and supporting methodology for the schedules and exhibits that are included in PGW's base rate filing; 2) describe PGW's financial results for the test year (the 12 months ending August 31, 2010); and 3) detail and provide supporting justification for PGW's requested increase in existing annual base rates of $42.5 million (in year one).

II. <u>BACKGROUND FOR CONSIDERATION OF RATE REQUEST</u>

Q. PLEASE PROVIDE THE BACKGROUND OF PGW'S CURRENT FINANCIAL CONDITION.

A. PGW last received an increase in base rates in December 2008 when the Commission granted its request for extraordinary/emergency rate relief in the amount of $60 million. In that Order, the Commission directed PGW to file a base rate case by the end of 2009 in which the reasonableness of PGW's base rates could examined, together with any other requests for rate increase.

Q. WHAT HAS BEEN THE EFFECT OF THE EXTRAORDINARY/EMERGENCY RATE INCREASE ON THE COMPANY'S FINANCIAL STATUS?

A. The extraordinary rate increase enabled PGW to successfully maneuver through several financial crises that it was facing at the time the Commission granted the rate increase in December of last year. The first involved PGW's commercial paper program. As background, PGW's rates typically do not produce sufficient cash working capital to satisfy all of its needs and must be supplemented by the issuance of commercial paper notes. PGW relies on this program to satisfy its cyclical cash working capital needs; mainly natural gas purchases and accounts receivable growth. The current program is backed by an irrevocable letter of credit supplied by a consortium of banks for $150.0 million.

During the period beginning in mid-September 2008, PGW had $17.0 million of outstanding notes maturing. As a result of the credit crisis that was being experienced, PGW could not remarket these notes for a two week period. On October 10, 2008 PGW did reissue the $17.0 million plus an additional $58.0 million, bringing the total level of notes outstanding to $148.0 million maturing in February and March 2009. After the extraordinary rate increase was granted, PGW successfully reissued $75.0 million of notes that matured on February 12, and 13, 2009 at a rate of 60 and 65 basis points through May 15, 2009. The next portion of notes, $73.0 million, matured on March 12, 2009 and was successfully reissued at a rate of 50 basis points through May 8, 2009. PGW paid off the full $148.0 million of maturing notes on May 8 and May 15, 2009. It is clear that the Commission's order providing a rate increase of $60 million was very important, if not essential, in enabling PGW to complete those transactions. At the end of

FY 2009, PGW did not have any commercial paper outstanding (the first time in many years).

Q. PLEASE SUMMARIZE RECENT ACTIVITY REGARDING PGW'S LONG TERM DEBT.

A. PGW currently has approximately $1.16 billion of outstanding long term debt with maturities through fiscal year 2039. Of that amount, approximately $900 million is in fixed rate securities about which there is no concern. However, PGW's 6th Series $313.4 million 1998 Ordinance debt was issued in a variable rate mode with a three bank consortium supporting the transaction. These variable rate bonds were set through a weekly reset mode, are paid monthly, and were secured by a Standby Bond Purchase Agreement which expired on January 26, 2009.

PGW was informed in late August 2008 by the lead bank that the consortium would not renew the Standby Bond Purchase Agreement. The bonds were not able to be remarketed during the financial turmoil at that time and the remaining portion, totaling $311.6 million, was held by the consortium banks. The City of Philadelphia and PGW examined all available options to remarket these bonds either in another variable rate or of fixed rate mode. One significant obstacle was an interest rate swap agreement that had to be terminated if the bonds were refunded in their entirety. At various points in time the swap termination payment varied from $20.0 million to over $60.0 million reflecting the significant swings in interest rates.

Through the efforts of the City and PGW's Financial Advisor (Ms. Bisgaier), the City of Philadelphia and PGW refunded the full $311.6 million of outstanding 6th Series Bonds and reissued $255.0 million of variable rate 8th Series Bonds and $58.285 million fixed rate bonds. The City of Philadelphia and PGW will keep the existing interest swap in effect as an interest rate hedge on the \$255.0 million variable rate 8^{th} Series Bonds. The City and PGW terminated the swap associated with \$54.8 million of the fixed rated bonds. The cost of terminating this portion of the swap agreement was \$3.8 million. The bank fees for providing a direct pay letter of credit in support of the 8^{th} Series variable rate bonds was approximately \$6.6 million, an increase of \$5.8 million.

The current valuation of the swap termination payment for the remaining swap is approximately \$32.3 million. The \$32.3 million reflects market conditions at a fixed point in time and change not only from day-to-day but also during the course of a day. If the bonds associated with this portion of the swap are refunded, the associated payments will be based upon the market conditions that exist at the time of the transaction.

PGW and the City of Philadelphia closed the 8^{th} Series Bonds transaction on August 20, 2009. Absent the planned refunding, the first scheduled accelerated payment of \$31.2 million would have been due in August 2009. It should also be noted that the fixed rate bonds (i.e., the \$58.285 million) were successfully issued without bond insurance basically because they had short term maturities. Selling bonds with longer term maturities without bond insurance will be an issue. Nonetheless, this is the first time in recent memory that PGW was able to issue any portion of a bond without bond insurance. Ms. Bisgaier explains the significance of this in her testimony.

Q. WHAT PLANS DOES PGW HAVE TO SELL BONDS IN THE FORESEEABLE FUTURE?

A. PGW plans to access the financial markets for a new money bond issue to provide proceeds in support of its on-going capital expenditure programs in September or October of 2010. PGW currently has nearly \$53.0 million of remaining proceeds from its 2007, 7^{th} Series Bond issue. PGW is reviewing its options regarding capital expenditures for the remainder of the 2010 period. In its recent history, PGW's capital spending has been in the range of between $60.0 to $70.0 million annually.[1] Although the financial markets may be easing access somewhat, there is no guarantee that PGW will be able to access the financial markets at reasonable rates when the need arises. This is especially the case because PGW expects to have to issue fully 100% of these bonds with long maturity terms without bond insurance.

III. PRO FORMA FINANCIAL RESULTS

Q. HAVE YOU PREPARED A PRO FORMA TEST YEAR INCOME STATEMENT THAT PROJECTS THE COMPANY'S STATUS IN FY 2010?

A. Yes. Exhibit JRB-1 provides the base test year data at present rates. I will describe the development of these data below. Also, I am sponsoring Exhibit JRB-3, which is the detailed schedules and supporting material for PGW's original budget submitted to the Philadelphia Gas Commission ("PGC"), which form the basis for the *pro forma* test year.

As can be seen, PGW's projected net income for the test year is just $36.8 million. This level will permit PGW to make its required 1.5x bond ordinance debt coverage (on its 1998 Ordinance bonds), and produce a 1998 coverage of 2.1 times) and satisfy the total fixed coverage charge as calculated by S&P,[2] necessary to maintain an investment grade debt rating (1.40x).

On an adjusted, *pro forma* basis PGW's year end non-borrowed cash will be approximately $50 million and PGW will have approximately $17 million in commercial

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1 Notably, PGW reduced its FY 2009 capital program to $54.9 million because of its concern that it would not be able to finance its full program. PGW is committed to its regular level of capital additions in FY 2010.

2 S&P's calculation looks at income verses all external funding.

paper outstanding. As a result, PGW projects it will have some $22 million in internally generated funds ("IGF") that will be available to fund its capital program.[3] After FY 2009, in which PGW ended the year (on an actual basis) with $9.9 million of internal generation, this marks the first time since the early to mid 1990's that PGW will have IGF available to finance a portion of its capital program. While this improvement – due to the Commission's $60 million extraordinary rate increase – is a positive sign, PGW's year-end cash working capital continues to fall well short of adequate levels. Moreover, notwithstanding this improvement, for a variety of reasons, PGW continues to be very highly leveraged (82% in the test year).

Again, Ms. Bisgaier explains the significance of PGW's attempting to issue these bonds fully without bond insurance and the crucial need for continued progress if PGW is to be successful in marketing the bonds without insurance.

IV. CALCULATION OF PRO FORMA TEST YEAR

Q. MR. BOGDONAVAGE, PLEASE EXPLAIN THE DERIVATION OF THE PRO FORMA TEST YEAR INFORMATION AT PRESENT RATES.

A. As indicated, those schedules are displayed in Exhibit JRB-1. In that Exhibit, I have provided schedules which show PGW's Income Statement, Cash Flow Statement, Debt Service Coverage Statement and Balance Sheet derived from the approved budget for the test year, the 12 months ending August 31, 2010. The development of the test year starts with the "fully forecasted" budget as approved by the PGC for that fiscal year as a starting point and then makes certain budget and *pro forma* adjustments.

Q. PLEASE EXPLAIN THE REVISIONS TO PGW'S APPROVED BUDGET THAT WERE MADE AND THE REASON FOR MAKING THEM?

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3 In this context, PGW calculated internally generated funds as the difference between its capital spending and amount withdrawn from the capital fund.

A. The following adjustments were made to PGW's operating budget:

1. Administrative and General expense has been reduced by $1 million to eliminate the inclusion of a contingency amount that reflected projected expenditures that PGW anticipated it would incur to prepare for a work stoppage in May 2010. This amount was removed by the PGC because it was viewed as too speculative.

2. BT Supply Chain Initiative. This $155,000 adjustment to net income reflects the net effect of amortizing over three years the costs ($4.1 million) and the benefits ($4,6 million) over three years of PGW's "Business Transformation Supply Chain Initiative." The difference between the one- year amounts ($1.5 million in benefits verses $1.376 million in costs) produces the *pro forma* downward adjustment to total operating expenses. An adjustment in non-cash working capital has also been made to reflect the $4.1 million Supply Chain Initiative cost.

3. New Money Bond Issuance. PGW plans to sell $150 million in new long term bonds in the September-October, 2010 timeframe. Accordingly, PGW has adjusted the *pro forma* test year to reflect the annual effect of the cost of this additional debt. The adjustments include: a) increasing long term debt interest by $9 million (with a corresponding adjustment to the debt service calculation to reflect increased debt service of $11 million) and an increase of $.1 million reflecting bond discount and issuance costs related to the $150 million issuance; b) an increase of $3.8 million in Other Income to reflect the projected level of interest PGW will earn on the debt proceeds prior to their expenditure as well as the funds deposited in the requisite sinking fund; and c) an increase in PGW's *pro forma* "uses of funds" reflecting the $2 million increase in revenue bond debt service resulting from the projected bond sale.

These adjustments are detailed on JRB-1, pp. 5-6.

Q. MR. BOGDONAVAGE, WHAT ASSUMPTIONS AND EXPENSE ADJUSTMENTS WERE INCLUDED IN PGW'S APPROVED BUDGET WHICH ALSO SERVE TO MAKE THE TEST YEAR REPRESENTATIVE OF FUTURE PERIODS?

A. Several "pro forma" adjustments have already been made to the Budget as part of the preparation or approval of the FY 2010 budget before the PGC. These adjustments, which are embedded in the FY 2010 Budget figures on JRB-1, are as follows:

1. Rate Case Expense. PGW's present estimate of rate case expense has been included on a five year amortized basis. Also included in the five-year amortization is the remaining portion of rate case expense from the 2006-07 proceeding as well as the

rate case expense associated with the 2008, $60 million Extraordinary/Emergency rate case. These too have been amortized over five years.

2. The cost of the PUC Management Audit, which was completed in FY 2009, has been amortized over seven years.

3. In FY 2009 PGW installed a Time and Labor Management System. The expense associated with this new system was amortized over five years and the budget/test year includes one-fifth of this charge.

Q. ARE THERE ANY ASSUMPTIONS CONTAINED IN THE FY 2010 BUDGET THAT YOU BELIEVE MAY REQUIRE ADJUSTMENT?

A. Yes. I am concerned about a material difference in the level of LIHEAP grants being received by PGW's customers compared to past years. As Ms. Coltro indicates, at present, PGW is approximately $8.8 million and 21,500 grants below this same point last year. If this trend continues, the actual level of LIHEAP grants in FY 2010 will be much lower than projected. In turn, this lower level of grants will affect PGW's cash working capital, as reflected in year end cash, and its cash receipts realization. At this point, PGW has elected not to make a change in its *pro forma* statistics, but may need to do so in the future as this trend becomes more clear.

Q. CAN YOU PROVIDE AN EXPLANATION OF THE DERIVATION OF THE 5-YEAR BUDGET PROJECTIONS THAT APPEAR IN YOUR EXHIBIT?

A. Yes. The five year, post-test year budget projections are consistent with similar projections that PGW prepared and submitted with its budget review process to the PGC, although the budgets have been adjusted to reflect the above adjustments and revisions. PGW is required to prepare these five-year projections for the PGC budget process. While PGW is not relying on them in any way to justify its claimed test year revenue requirement, it continues to believe that such projections are a necessary tool and provide the Commission with a view of what the Company expects to occur in the future as current trends work forward.

V. EXPLANATION OF RATE INCREASE REQUEST

Q. PLEASE EXPLAIN THE JUSTIFICATION OF THE $42.5 MILLION RATE INCREASE THAT PGW IS REQUESTING.

A. The rate increase reflects the revenue requirement effect of the change in the method of calculating the expense associated with post-employment benefits other than pensions ("OPEBs"). Government Accounting Standards Board Standard ("GASB") 45 requires government entities to use an accrual method versus the cash (pay-as-you-go) method for recording post-employment benefits expense for financial accounting purposes. PGW implemented this change in accounting starting in FY 2007. This change is identical to the accounting changes mandated in the early 90's by the Financial Accounting Standards Board in FASB 106 for nongovernment entities.

Furthermore, PGW has a substantial balance of post-employment benefits liability associated with current employees. As PGW's actuarial consultant Mr. Kickla testifies, the accrued liability is projected at $653 million for the test year. He also explains that, absent funding, the expense will increase substantially each year. Therefore, to mitigate increases in expense, PGW proposes to fund the actuarially determined present value liability over 30 years. Because GASB 45 permits PGW to calculate its funded liability using a higher assumed interest rate (8.25% verses 5%), PGW's funded liability is significantly reduced. PGW's funded present value liability for which ratepayers will be responsible is approximately $200 million lower ($455 million versus $653) than its unfunded liability

Finally, in order to fully fund the projected liability it is necessary to recover the difference between pay as you go and the accrued liability that has been recorded on PGW's books since FY 2007. PGW proposes to recover the $105.1 million amount (the total amount anticipated to be recorded through the test year) over five years. Again Mr. Kickla explains the need for this in greater detail. The financial effects of funding PGW's OPEB liability are shown on JRB-2A. The effects of funding without a corresponding rate increase are shown on schedule JRB-2B. Obviously funding PGW's OPEB liability out of current rates would put PGW into an immediate financial crisis because it would leave it with inadequate cash flow and liquidity. Again, funding this OPEB liability through a rate increase is consistent with the treatment afforded investor-owned utilities by the PUC to fund the liability associated with the implementation of FASB 106.

Q. WHAT WILL PGW DO WITH THE RATE INCREASE ASSOCIATED WITH FUNDING PGW'S OPEB LIABILITY?

A. PGW will establish an irrevocable trust fund and deposit the amounts permitted by this rate increase into the fund in order to separately fund its OPEB liability. Thus, the funds recovered due to this rate increase will not be directly available to PGW and will not be available to provide end of year cash working capital or internally generated funds. These funds will be invested in roughly the same manner that pension funds are normally invested. As noted, because of the funding, PGW is permitted to assume that the investments will earn a return of 8.25% over thirty years, producing a return of approximately $200 million, an amount that customers will not have to pay toward these requirements.

Q. HOW WILL THE RATE INCREASE FOR OPEB FUNDING AFFECT PGW'S KEY FINANCIAL INDICATORS?

A. PGW's net income will increase by roughly the amount of the rate increase, but, since all of the rate increase will be placed in a trust fund and is not available to pay for general operations or for any other purpose, the increase will have no effect on PGW's debt service or fixed charge coverages. Also, PGW's year-end available cash is essentially unchanged and its outstanding commercial paper will improve over the non-funded assumption because PGW will not have to utilize its otherwise available net income to account for the accrued amount it is booking in the test year. Thus, PGW will realize approximately $17 million in additional liquidity by the funding and reflecting in rates of the unfunded liability.

Q. WILL THE FUNDING OF PGW'S OPEB LIABILITY HAVE ANY OTHER SALUTARY EFFECTS ON PGW'S FINANCES?

A. Yes. By funding PGW's projected OPEB liability PGW's debt-to-total capitalization will improve in the test year and over the next five years. As can be observed by comparing JRB-1 with JRB-2A, with funding, PGW's debt-to-total capitalization ratio improves marginally, but immediately, in the test year from 82% to 80%. By FY 2015, PGW's debt to total capitalization will improve to 61% debt – 39% equity, compared to 71%/29% without funding PGW's OPEB liability. In addition, if PGW is required to deposit its annual funding amount once yearly, the funding process may create intra-year cash working capital for PGW. However, PGW is still exploring what the requirements of the trust fund will be.

Q. YOU INDICATED THAT THE FIRST YEAR REVENUE REQUIREMENT TO FUND OPEBS IS $42.5 MILLION. WHAT LEVEL WILL BE NEEDED TO FUND OPEBS IN SUBSEQUENT YEARS?

A. Mr. Kickla's analysis projects that PGW's funding requirements will steadily decrease each year as the OPEB trust fund earns interest on the balance in the account. As noted above, funding also permits PGW to assume an earnings rate of 8.25% on the fund balance when calculating the amount needed to fully satisfy funding requirements. As a result the funding amounts in years after the test year are projected to go down each year as follows: FY 2011: $39M; FY 2012: $35.3M; 2013: $32M; 2014: $28M; 2015: $7M. (JRB-2A).

Q. DOES PGW HAVE A PROPOSAL TO DEAL WITH THIS PROJECTED GOING FORWARD DECREASE IN REVENUE REQUIREMENT?

A. Yes. PGW believes that the fairest approach would be to adjust its base rates each year to reflect the amount needed to fund OPEBs based upon an annually updated actuarial study. This could be accomplished either by establishing a process by which PGW files an annual single issue rate case or by authorizing PGW to file an automatic adjustment clause pursuant to Section 1307 of the Public Utility Code, similar to PGW's Gas Cost Rate or Universal Service Charge. Such filing would, of course, be subject to review by the parties prior to Commission approval, in the same manner as the annual GCR and USC filings. PGW sees advantages and drawbacks of each approach, but rather than advocate for one specific method, PGW believes it more appropriate to leave it to the Commission to determine the method that should be implemented.

Q. IS ANOTHER OPTION TO AUTHORIZE PGW TO RAISE ITS RATES BASED ON THE FIVE YEAR AVERAGE OF THE ANNUAL LEVELS NEEDED TO FUND OPEB LIABILITY?

A. No. As PGW will be required to actually deposit in the trust fund the annual amounts projected to be needed to fund the liability, permitting PGW to raise rates to reflect the five-year average annual amount will result in PGW having to fund out of its other earnings the difference between the average and actual funding levels in the early years. This will have a negative effect on PGW's financial metrics and could threaten its ability to accomplish its key financial transactions, as described in Ms. Bisgaier's testimony. In the back years, an average rate allowance would result in a windfall above its actual funding requirement and would then distort PGW's true financial status which could be misleading to investors and bad for the Company.

Q. COULD PGW BEGIN TO FUND ITS OPEB LIABILITY WITHOUT RECEIVING A RATE INCREASE TO ACCOUNT FOR THE INCREASED EXPENSE?

A. No, as I have already stated, a failure to permit a rate increase for the funding would have a severe negative effect on PGW. This is shown on Exhibit JRB-2B. If PGW were required to fund its liability from existing rates it would essentially reverse the effect of the Extraordinary/Emergency Rate case and have an immediate and dramatically negative effect on PGW's key financial statistics, plunging PGW back to the status of living on borrowed funds. Ms. Bisgaier comments on the negative effect that such a change would have on the investment community and PGW's access to the market. The PUC's awarding of the extraordinary/emergency rate increase has begun to move PGW away from its extremely precarious position. PGW could not and would not voluntarily move back to that status.

Q. BESIDES FUNDING OPEBS, WHAT OTHER EXPENSES HAVE INCREASED SINCE PGW'S LAST GENERAL RATE CASE BUT FOR WHICH PGW HAS NOT MADE A SPECIFIC CLAIM FOR INCREASED RATES?

A. Since PGW's 2006-07 test year, material increases in costs include:

- Health Insurance (for current employees, for current periods) have increased by $3.3 mil;
- Pension expense has increased by $9.0 million;
- Long term debt interest has gone up by $5.4 million and debt principal obligations have increased by $10 million.

The total expense increased amount to $28.0 million. In addition, PGW expended about $3.8 million in FY 2009 to pay the swap termination fee for the portion of the swap that PGW terminated.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

PHILADELPHIA GAS WORKS
STATEMENT OF INCOME
(Dollars In Thousands)

Existing Rates OPEB Reported Only

	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
OPERATING REVENUES											
Non-Heating	$91,131	$78,687	$66,596	$50,190		$50,190	$49,736	$48,355	$46,752	$45,600	$43,377
Gas Transport Service	12,949	19,215	25,358	30,084		30,084	32,145	34,294	35,759	36,864	37,777
Heating	732,084	723,535	828,245	742,086		742,086	791,622	820,156	835,690	856,785	867,707
Proposed Base Rate	-	-	-	-		-	-	-	-	-	-
Weather Normalization Adjustment	6,438	11,922	-	-		-	-	-	-	-	-
Unbilled Adjustment	(2,497)	(1,931)	596	(1,037)		(1,037)	970	366	205	275	135
Total Gas Revenues	840,105	831,428	920,795	821,323		821,323	874,473	903,171	918,406	939,524	948,996
Appliance Repair & Other Revenues	9,398	8,607	8,745	8,972		8,972	9,151	9,334	9,521	9,712	9,906
Other Operating Revenues	9,848	9,592	10,553	9,114		9,114	9,947	10,281	10,456	10,696	10,806
Total Other Operating Revenues	19,246	18,199	19,298	18,086		18,086	19,098	19,615	19,977	20,408	20,712
Total Operating Revenues	859,351	849,627	940,093	839,409		839,409	893,571	922,786	938,383	959,932	969,708
OPERATING EXPENSES											
Natural Gas	539,296	511,938	546,951	420,056		420,056	463,521	494,153	511,506	535,273	545,178
Other Raw Material	4	38	20	20		20	20	20	20	20	20
Sub-Total Fuel	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
CONTRIBUTION MARGINS	**320,051**	**337,651**	**393,122**	**419,333**		**419,333**	**430,030**	**428,613**	**426,857**	**424,639**	**424,510**
Gas Processing	16,240	14,436	16,584	14,297		14,297	14,721	15,743	15,857	16,495	17,212
Field Services	36,100	37,126	36,121	34,682		34,682	35,815	36,829	37,816	38,919	39,921
Distribution	17,119	17,319	20,779	19,889		19,889	20,335	20,814	21,352	21,926	22,635
Collection	8,157	8,441	9,122	9,446		9,446	9,686	9,883	10,181	10,510	10,870
Customer Service	11,783	12,305	13,470	14,410		14,410	14,673	14,963	15,282	15,657	16,064
Account Management	7,064	7,006	7,480	7,879		7,879	7,974	8,118	8,290	8,581	8,835
Bad Debt Expense	40,000	37,000	47,111	43,399		43,399	39,985	37,698	36,136	35,241	34,825
Marketing	2,418	2,628	3,652	4,536		4,536	4,056	4,062	4,066	4,138	4,210
Administrative & General	38,846	44,001	44,773	52,615	(1,000) **A.**	51,615	50,014	50,530	51,033	51,512	52,362
Health Insurance	36,111	34,226	37,300	41,139		41,139	46,926	51,377	56,234	61,730	67,964
Capitalized Fringe Benefits	(10,449)	(10,331)	(9,214)	(10,572)		(10,572)	(12,225)	(13,024)	(13,617)	(14,266)	(15,009)
Capitalized Administrative Charges	(7,689)	(7,180)	(6,731)	(7,181)		(7,181)	(7,618)	(8,143)	(7,714)	(7,686)	(7,674)
BT Supply Chain Initiative	-	-	-	-	(155) **B.**	(155)	2,184	758	(1,979)	(2,614)	(3,251)
Pensions	15,217	14,258	15,531	24,062		24,062	23,805	23,533	23,279	23,022	22,692
Taxes	6,730	5,677	6,609	6,875		6,875	7,019	7,165	7,313	7,455	7,603
Other Post Employment Benefits	26,421	25,834	25,952	25,223	1,682 **C.**	26,905	25,833	25,277	24,453	23,338	21,880
BT Lite Costs/(Benefits)	-	-	3,000	-						-	-
Cost / Labor Savings	-	-	(1,419)	(2,503)		(2,503)	(1,957)	(1,202)	(561)	(230)	(235)
Sub-Total Other Oper.& Maintenance	244,068	242,746	270,120	278,196	527	278,723	281,226	284,381	287,421	293,728	300,904
Depreciation	37,166	40,021	39,280	40,409		40,409	41,907	43,506	44,858	46,088	47,188
Cost of Removal	2,542	2,847	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
To Clearing Accounts	(3,328)	(3,344)	(4,419)	(4,802)		(4,802)	(5,398)	(5,631)	(5,808)	(5,872)	(6,254)
	36,380	39,524	37,861	38,607		38,607	39,509	40,875	42,050	43,216	43,934
Sub-Total Other Oper. & Maint. & Depreciation	280,448	282,270	307,981	316,803	527	317,330	320,735	325,256	329,471	336,944	344,838
TOTAL OPERATING EXPENSES	819,748	794,246	854,952	736,879	527	737,406	784,276	819,429	840,997	872,237	890,036
OPERATING INCOME	39,603	55,381	85,141	102,530	(527)	102,003	109,295	103,357	97,386	87,695	79,672
Other Income	13,073	15,732	9,785	9,218	3,801 **D.**	13,019	12,299	12,555	11,712	11,499	10,882
INCOME BEFORE INTEREST	52,676	71,113	94,926	111,748	3,274	115,022	121,594	115,912	109,098	99,194	90,554
INTEREST											
Long-Term Debt	52,146	56,075	63,436	52,771	9,000 **E.**	61,771	59,717	56,997	54,734	52,338	49,757
Other	11,411	6,812	5,864	11,558	64 **F.**	11,622	14,928	15,638	15,563	15,546	15,528
Swap Termination Payment	-	-	3,791	-		-	-	-	-	-	-
AFUDC	(408)	(338)	(399)	(865)		(865)	(925)	(984)	(825)	(822)	(813)
Loss From Extinguishment of Debt	5,631	5,457	5,181	5,734		5,734	5,495	5,238	5,001	4,603	4,148
Total Interest	68,780	68,006	77,873	69,198	9,064	78,262	79,215	76,889	74,473	71,665	68,620
NET INCOME	**($16,104)**	**$3,107**	**$17,053**	**$42,550**	**($5,790)**	**$36,760**	**$42,379**	**$38,023**	**$34,625**	**$27,529**	**$21,934**

PHILADELPHIA GAS WORKS
CASHFLOW STATEMENT
(Dollars In Thousands)

Existing Rates OPEB Reported Only	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
SOURCES											
Net Income	($16,104)	$3,107	17,053	$42,550	($5,790)	$36,760	$42,379	$39,023	$34,625	$27,529	$21,934
Depreciation & Amortization	44,427	46,660	45,520	46,520	64	46,584	47,805	49,113	50,152	50,967	51,595
Earnings on Restricted Funds	(6,650)	(11,851)	(177)	(4,285)	(3,801)	(8,086)	5,409	5,503	6,696	1,750	227
Elimination of Accrued Interest on Refunded Debt	728	-	-	-		-	-	-	-	-	-
Increased/(Decreased) Other Assets/Liabilities	27,963	25,403	28,649	22,052	1,682	23,734	16,222	13,330	23,423	22,103	21,188
Available From Operations	50,364	63,319	91,045	106,837	(7,845)	98,992	111,815	106,969	114,896	102,349	94,944
Funds Required for Capital	65,000	70,000	45,000	50,000		50,000	50,000	40,000	25,000	24,878	-
Grant Income	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
	-	-	-	-		-	-	-	-	-	-
FY 2009 Actual Cash Adjustment			31,649								
Release of Sinking Fund Asset	6,624	-	-	-		-	-	-	-	-	-
Temporary Financing	-	38,400	-	5,000	12,000 G.	17,000	-	-	-	-	-
TOTAL SOURCES	139,988	189,719	185,694	179,837	4,155	183,992	179,815	164,969	157,896	127,227	94,944
USES											
Net Construction Expenditures	70,018	61,742	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Funded Debt Reduction:											
Revenue Bonds	36,675	40,400	41,280	44,480	2,000 H.	46,480	36,284	35,127	45,489	47,494	50,706
Revenue Bond Subordinate Debt	1,370	1,430	1,500	1,565		1,565	1,640	1,715	1,805	1,890	-
FY 2010 Pro Forma Expense Adjustment							(11,000)				
Equity Bond Contribution/ Debt Reduction	-	-	1,209	-			-	-	-	-	18,000
Temporary Financing Repayment	3,400	-	90,000	-			17,000	-	-	-	-
City Loan Repayment/Status	2,000	43,000	-	-			-	-	-	-	-
Distribution of Earnings	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	18,000	18,000
Additions To (Reductions of)											
Non-Cash Working Capital	(36,476)	27,507	13,702	7,221	2,752 I.	9,973	(25,769)	2,375	7,118	12,521	10,534
Cash Needs	94,987	192,079	221,282	143,386	4,752	148,138	116,553	142,825	144,155	151,375	167,977
Cash Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	(597)	35,854	63,262	22,144	13,741	(24,148)	(73,033)
TOTAL USES	139,988	189,719	185,694	179,837	4,155	183,992	179,815	164,969	157,896	127,227	94,944
Cash - Beginning of Period	6,697	51,698	49,338	13,750		13,750	49,604	112,866	135,010	148,751	124,603
Cash - Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	(597)	35,854	63,262	22,144	13,741	(24,148)	(73,033)
ENDING CASH	51,698	49,338	13,750	50,201	(597)	49,604	112,866	135,010	148,751	124,603	51,570
Outstanding Commercial Paper	51,600	90,000	-	5,000	12,000	17,000	-	-	-	-	-
City Loan Outstanding	43,000	-	-	-		-	-	-	-	-	-
Internally Generated Funds	-	-	-	22,120	-	22,120	30,398	45,608	46,743	46,592	70,737

PHILADELPHIA GAS WORKS
DEBT SERVICE COVERAGE
(Dollars In Thousands)

Existing Rates OPEB Reported Only	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
FUNDS PROVIDED											
Total Gas Revenues	$840,105	$831,428	$920,795	$821,323		$821,323	$874,473	$903,171	$918,406	$939,524	$948,996
Other Operating Revenues	19,246	18,199	19,298	18,086		18,086	19,098	19,615	19,977	20,408	20,712
Total Operating Revenues	859,351	849,627	940,093	839,409		839,409	893,571	922,786	938,383	959,932	969,708
Other Income Incr. / (Decr.) Restricted Funds	6,423	3,881	9,608	4,933		4,933	17,708	18,058	18,408	13,249	11,109
City Grant	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
AFUDC (Interest)	408	338	399	865		865	925	984	825	822	813
TOTAL FUNDS PROVIDED	884,182	871,846	968,100	863,207		863,207	930,204	959,828	975,616	974,003	981,630
FUNDS APPLIED											
Fuel Costs	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
Other Operating Costs	280,448	282,270	307,981	316,803	527	317,330	320,735	325,256	329,471	336,944	344,838
Total Operating Expenses	819,748	794,246	854,952	736,879	527	737,406	784,276	819,429	840,997	872,237	890,036
Less: Non-Cash Expenses	66,246	68,898	69,034	68,817	1,682	70,499	70,861	71,904	72,442	72,588	72,205
TOTAL FUNDS APPLIED	753,502	725,348	785,918	668,062	(1,155)	666,907	713,415	747,525	768,555	799,649	817,831
Funds Available to Cover Debt Service	130,680	146,498	182,182	195,145		196,300	216,789	212,303	207,061	174,354	163,799
1975 Ordinance Bonds Debt Service	35,359	34,225	32,313	30,101		30,101	30,691	32,110	30,521	28,963	27,261
Debt Service Coverage 1975 Bonds	**3.70**	**4.28**	**5.64**	**6.48**		**6.52**	**7.06**	**6.61**	**6.78**	**6.02**	**6.01**
Net Available after Prior Debt Service	95,321	112,273	149,869	165,044	1,155	166,199	186,098	180,193	176,540	145,391	136,538
Other Capital Leases	-	-	-	-		-	-	-	-	-	-
Net Available after Prior Capital Leases	95,321	112,273	149,869	165,044	1,155	166,199	186,098	180,193	176,540	145,391	136,538
1998 Ordinance Bonds Debt Service	47,611	59,695	70,995	65,439		65,439	68,290	71,040	70,034	71,290	73,686
New Proposed Bond Debt Service	-	-	-	-	11,000 J.	11,000	-	-	-	-	-
Total New Debt Service	47,611	59,695	70,995	65,439	11,000	76,439	68,290	71,040	70,034	71,290	73,686
Debt Service Coverage 1998 Bonds	**2.00**	**1.88**	**2.11**	**2.52**		**2.17**	**2.73**	**2.54**	**2.52**	**2.04**	**1.85**
Net Available after 1998 Debt Service	47,710	52,578	78,874	99,605	(9,845)	89,760	117,808	109,153	106,506	74,101	62,852
1998 Ordinance Subordinate Bond Debt Service	1,987	1,986	1,990	1,986		1,986	1,986	1,984	1,990	1,985	-
Debt Service Coverage Subordinate Bonds	**24.01**	**26.47**	**39.64**	**50.15**		**45.20**	**59.32**	**55.02**	**53.52**	**37.33**	-
Net Available To Service Aggregate Debt Service	**115,885**	**136,809**	**159,895**	**176,443**	4,956	**181,399**	**187,861**	**183,048**	**176,426**	**166,570**	**157,181**
Aggregrate Debt Service Including TXCP	**93,055**	**100,005**	**108,301**	**100,521**	11,000	**111,521**	**107,312**	**112,224**	**109,635**	**109,328**	**108,037**
Fixed Coverage Charge	**1.25**	**1.37**	**1.48**	**1.76**	(0.13)	**1.63**	**1.75**	**1.63**	**1.61**	**1.52**	**1.45**
Fixed Coverage Charge Including $18.0 City Fee	**1.04**	**1.16**	**1.27**	**1.49**	(0.09)	**1.40**	**1.50**	**1.41**	**1.38**	**1.31**	**1.25**

PHILADELPHIA GAS WORKS
BALANCE SHEET
(Dollars in Thousands)

Existing Rates OPEB Reported Only	ACTUAL 8/31/07	ACTUAL 8/31/08	ESTIMATE 8/31/09	BUDGET 8/31/10	Pro Forma Adjustments	Adjusted BUDGET 8/31/10	FORECAST 8/31/11	FORECAST 8/31/12	FORECAST 8/31/13	FORECAST 8/31/14	FORECAST 8/31/15
ASSETS											
Utility Plant Net	$1,040,373	$1,062,095	$1,078,406	$1,110,117		$1,110,117	$1,148,608	$1,190,710	$1,217,595	$1,242,977	$1,266,526
Sinking Fund Reserve	102,438	106,198	109,285	112,609	11,489	124,098	120,575	117,988	115,295	114,992	114,677
Capital Improvement Fund	172,134	111,207	63,326	14,289	139,912	154,201	98,459	55,476	26,403	-	-
Restricted Investment Workers' Compensation Fund											
& City of Philadelphia	2,567	2,383	2,594	2,634		2,634	2,687	2,755	2,824	2,910	2,999
Debt Reduction Funding	-	-	-	-						-	-
Cash	51,698	49,338	13,750	50,201	(597)	49,604	112,866	135,010	148,751	124,603	51,570
Gas	226,529	222,880	235,582	225,165		225,165	215,543	205,983	200,234	198,126	198,734
Other	2,245	8,714	9,150	9,425		9,425	3,550	3,450	3,350	3,250	3,150
Accrued Gas Revenues	10,075	8,145	8,741	7,704		7,704	8,674	9,040	9,245	9,520	9,655
Reserve for Uncollectible	(150,231)	(140,435)	(137,820)	(133,619)		(133,619)	(127,504)	(120,152)	(112,238)	(104,429)	(97,204)
Accounts Receivable:	88,618	99,304	115,653	108,675		108,675	100,263	98,321	100,591	106,467	114,335
Materials & Supplies	147,770	187,539	134,922	127,758		127,758	129,859	136,735	143,770	151,744	154,624
Other Current Assets	2,437	2,317	5,989	6,296		6,296	6,427	6,555	6,686	6,819	6,955
Deferred Debits	3,178	3,309	7,317	8,190	2,752	10,942	5,118	2,942	2,586	2,277	2,227
Unamortized Bond Issuance Expense	42,086	38,738	27,469	24,961	1,460	26,421	24,059	21,751	19,575	17,531	15,626
Unamortized Extraordinary Loss	53,359	47,902	53,742	47,391		47,391	41,896	36,659	31,658	27,054	22,906
Deferred Environmental	4,847	12,650	12,961	12,961		12,961	12,961	12,961	12,961	12,961	12,961
FY 2009 Actual Cash Adjustment			(31,649)	(31,649)		(31,649)	(31,649)	(31,649)	(31,649)	(31,649)	(31,649)
Other Assets	3,435	6,685	3,828	2,163		2,163	1,892	1,624	1,463	1,484	1,508
TOTAL ASSETS	1,714,940	1,729,665	1,597,593	1,596,596	155,016	1,751,612	1,774,021	1,787,838	1,798,509	1,780,170	1,735,265
EQUITY & LIABILITIES											
City Equity	223,301	226,408	243,461	286,011	(5,790)	280,221	326,708	365,731	400,556	410,085	414,019
Revenue Bonds	1,204,285	1,162,455	1,121,345	1,075,300	148,000	1,223,300	1,187,376	1,150,534	1,103,330	1,053,946	1,003,240
TECA Accretions	13,913	15,314	16,818	18,434		18,434	10,933	-	-	Debt Reduction	(18,000)
Unamortized Discount	(5,462)	(4,951)	(3,719)	(3,323)	(876)	(4,199)	(3,850)	(3,500)	(3,190)	(2,895)	(2,616)
Unamortized Premium	33,051	30,375	28,221	24,961		24,961	23,322	21,033	18,839	16,777	14,851
Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	997,475
Notes Payable	51,600	90,000	-	5,000	12,000	17,000	-	-	-	-	-
City Loan	43,000	-	-								
Accounts Payable	60,615	67,508	38,645	37,250		37,250	47,816	49,336	51,430	52,003	52,370
Customer Deposits	9,049	7,325	3,250	3,350		3,350	3,750	4,000	4,250	4,500	4,750
Other Current Liabilities	4,162	8,264	1,145	1,174		1,174	1,748	1,896	2,050	2,805	2,937
Deferred Credits	11,362	24,317	23,883	4,997		4,997	2,983	1,836	1,714	1,690	1,681
Accrued Interest	12,290	12,391	11,000	10,675		10,675	14,848	14,486	13,970	13,465	12,980
Accrued Taxes & Wages	2,798	3,430	3,021	3,315		3,315	3,380	3,482	3,585	3,689	3,734
Accrued Distribution to City	3,000	3,000	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
Other Liabilities	47,976	83,829	107,523	126,452	1,682	128,134	152,007	176,004	198,975	221,105	242,319
TOTAL EQUITY & LIABILITIES	1,714,940	1,729,665	1,597,593	1,596,596	155,016	1,751,612	1,774,021	1,787,838	1,798,509	1,780,170	1,735,265

CAPITALIZATION	ACTUAL FY2007	ACTUAL FY2008	ESTIMATE FY2009	BUDGET FY2010	Pro Forma Adjustments	- Adjusted BUDGET 8/31/10	FORECAST FY2011	FORECAST FY2012	FORECAST FY2013	FORECAST FY2014	FORECAST FY2015
Total Capitalization	1,469,088	1,429,601	1,406,126	1,401,383	143,016	1,542,717	1,544,489	1,533,798	1,519,535	1,477,913	1,411,494
Total Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	997,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796		0.818	0.788	0.762	0.736	0.723	0.707
Capitalization Ratio	5.58	5.31	4.78	3.90		4.51	3.73	3.19	2.79	2.60	2.41
Total Capitalization Excluding Leases	1,469,088	1,429,601	1,406,126	1,401,383			1,544,489	1,533,798	1,519,535	1,477,913	1,411,494
Total Long Term Debt Excluding Leases	1,245,787	1,203,193	1,162,665	1,115,372			1,217,781	1,168,067	1,118,979	1,067,828	997,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796			0.79	0.76	0.74	0.72	0.71
Plant in Service	1,620,791	1,681,313	1,732,562	1,788,153		1,788,153	1,860,273	1,940,671	2,026,279	2,098,022	2,169,492
Capital - 106&107	60,522	51,249	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Total Plant	1,681,313	1,732,562	1,788,153	1,860,273		1,860,273	1,940,671	2,026,279	2,098,022	2,169,492	2,240,229
Accumulated Depreciation	(640,940)	(670,467)	(709,747)	(750,156)		(750,156)	(792,063)	(835,569)	(880,427)	(926,515)	(973,703)
Net Utility Plant	1,040,373	1,062,095	1,078,406	1,110,117		1,110,117	1,148,608	1,190,710	1,217,595	1,242,977	1,266,526

PHILADELPHIA GAS WORKS

FISCAL YEAR 2010
OPERATING BUDGET ADJUSTMENTS

Existing Rates OPEB Reported ONLY

STATEMENT OF INCOME

A. Administrative & General (\$1,000,000)

The \$1.0 million reduction in Administrative & General costs reflects the elimination of anticipated expenditures in preparation for a work stoppage in May 2010.

B. BT Supply Chain Initiation (\$155,000)

The net benefit of \$.2 million reflects the implementation of the Business Transformation Initiative related to Supply Chain activities. The initiative is expected to cost \$4.1 million which was amortized over a three year period at \$1.376 million annually. Also, a three year benefit stream of \$4.6 million was annualized resulting in a reduction of \$1.5 million.

C. Other Post Employment Benefits \$1,682,000

The added expense reflects the most recent actuarially computed annual liability for PGW's post employment benefits.

D. Other Income \$3,801,000

The \$3.8 million increase in Other Income reflects the pro-forma inclusion of a projected \$150.0 million new money bond issue with the requisite sinking fund and capital improvement fund deposits. These funds would earn interest from the time of the sale.

E. Long-Term Debt Interest \$9,000,000

The \$9.0 million increase in long-term debt interest reflects the pro-forma inclusion of annual interest cost at 6%.

F. Other Interest \$64,000

The \$.1 million rise in other interest costs reflects bond discount and issuance costs related to the \$150.0 million bond sale.

CASHFLOW STATEMENT

G. **Sources - Temporary Financing $12,000,000**

The $12.0 million increase in commercial paper notes outstanding results from the interest and principal payments on the proposed bond sale.

H. **Uses - Revenue Bonds $2,000,000**

The $2.0 million increase in revenue bond debt service represents the payment of principal on the proposed bond sale.

I. **Non-Cash Working Capital $2,752,000**

The $2.8 million increase in working capital requirements represents the amortization of the $4.1 million Supply Chain Initiative cost over a three year period at $1.376 million annually.

DEBT SERVICE COVERAGE

J. **New Proposed Bond Debt Service $11,000,000**

The $11.0 million increase in 1998 Ordinance revenue bond debt service reflects the interest and principal payments on the proposed $150.0 million new bond sale.

PHILADELPHIA GAS WORKS
STATEMENT OF INCOME
(Dollars In Thousands)

Rate Increase to fund OPEB Liability

	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
OPERATING REVENUES											
Non-Heating	$91,131	$78,687	$66,596	$50,190		$50,190	$49,736	$48,355	$46,752	$45,600	$43,377
Gas Transport Service	12,949	19,215	25,358	30,084		30,084	32,145	34,294	35,759	36,864	37,777
Heating	732,084	723,535	828,245	742,086		742,086	791,622	820,156	835,690	856,785	867,707
Proposed Base Rate	-	-	-	-	42,500 A.	42,500	39,000	35,500	32,000	28,000	7,000
Weather Normalization Adjustment	6,438	11,922	-	-		-	-	-	-	-	-
Unbilled Adjustment	(2,497)	(1,931)	596	(1,037)	471 B.	(566)	931	328	166	231	(98)
Total Gas Revenues	840,105	831,428	920,795	821,323	42,971	864,294	913,434	938,633	950,367	967,480	955,763
Appliance Repair & Other Revenues	9,398	8,607	8,745	8,972		8,972	9,151	9,334	9,521	9,712	9,906
Other Operating Revenues	9,848	9,592	10,553	9,114	484 C.	9,598	10,392	10,685	10,821	11,015	10,885
Total Other Operating Revenues	19,246	18,199	19,298	18,086	484	18,570	19,543	20,019	20,342	20,727	20,791
Total Operating Revenues	859,351	849,627	940,093	839,409	43,455	882,864	932,977	958,652	970,709	988,207	976,554
OPERATING EXPENSES											
Natural Gas	539,296	511,938	546,951	420,056		420,056	463,521	494,153	511,506	535,273	545,178
Other Raw Material	4	38	20	20		20	20	20	20	20	20
Sub-Total Fuel	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
CONTRIBUTION MARGINS	**320,051**	**337,651**	**393,122**	**419,333**		**462,788**	**469,436**	**464,479**	**459,183**	**452,914**	**431,356**
Gas Processing	16,240	14,436	16,584	14,297		14,297	14,721	15,743	15,857	16,495	17,212
Field Services	36,100	37,126	36,121	34,682		34,682	35,815	36,829	37,816	38,919	39,921
Distribution	17,119	17,319	20,779	19,889		19,889	20,335	20,814	21,352	21,926	22,635
Collection	8,157	8,441	9,122	9,446		9,446	9,686	9,883	10,181	10,510	10,870
Customer Service	11,783	12,305	13,470	14,410		14,410	14,673	14,963	15,282	15,657	16,064
Account Management	7,064	7,006	7,480	7,879		7,879	7,974	8,118	8,290	8,581	8,835
Bad Debt Expense	40,000	37,000	47,111	43,399	484 D.	43,883	40,828	38,858	37,571	36,907	36,530
Marketing	2,418	2,628	3,652	4,536		4,536	4,056	4,062	4,066	4,138	4,210
Administrative & General	38,846	44,001	44,773	52,615	(1,000) E.	51,615	50,014	50,530	51,033	51,512	52,362
Health Insurance	36,111	34,226	37,300	41,139		41,139	46,926	51,377	56,234	61,730	67,964
Capitalized Fringe Benefits	(10,449)	(10,331)	(9,214)	(10,572)		(10,572)	(12,225)	(13,024)	(13,617)	(14,266)	(15,009)
Capitalized Administrative Charges	(7,689)	(7,180)	(6,731)	(7,181)		(7,181)	(7,618)	(8,143)	(7,714)	(7,686)	(7,674)
BT Supply Chain Initiative	-	-		-	(155) F.	(155)	2,184	758	(1,979)	(2,614)	(3,251)
Pensions	15,217	14,258	15,531	24,062		24,062	23,805	23,533	23,279	23,022	22,692
Taxes	6,730	5,677	6,609	6,875		6,875	7,019	7,165	7,313	7,455	7,603
Other Post Employment Benefits	26,421	25,834	25,952	25,223	1,682 G.	26,905	21,507	18,227	14,713	10,968	6,949
BT Lite Costs/(Benefits)	-	-	3,000	-		-	-	-	-	-	-
Cost / Labor Savings	-	-	(1,419)	(2,503)		(2,503)	(1,957)	(1,202)	(561)	(230)	(235)
Sub-Total Other Oper.& Maintenance	244,068	242,746	270,120	278,196	1,011	279,207	277,743	278,491	279,116	283,024	287,678
Depreciation	37,166	40,021	39,280	40,409		40,409	41,907	43,506	44,858	46,088	47,188
Cost of Removal	2,542	2,847	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
To Clearing Accounts	(3,328)	(3,344)	(4,419)	(4,802)		(4,802)	(5,398)	(5,631)	(5,808)	(5,872)	(6,254)
	36,380	39,524	37,861	38,607		38,607	39,509	40,875	42,050	43,216	43,934
Sub-Total Other Oper. & Maint. & Depreciation	280,448	282,270	307,981	316,803	1,011	317,814	317,252	319,366	321,166	326,240	331,612
TOTAL OPERATING EXPENSES	819,748	794,246	854,952	736,879	1,011	737,890	780,793	813,539	832,692	861,533	876,810
OPERATING INCOME	39,603	55,381	85,141	102,530	42,444	144,974	152,184	145,113	138,017	126,674	99,744
Other Income	13,073	15,732	9,785	9,218	3,801 H.	13,019	12,299	12,555	11,712	11,499	10,882
INCOME BEFORE INTEREST	52,676	71,113	94,926	111,748	46,245	157,993	164,483	157,668	149,729	138,173	110,626
INTEREST											
Long-Term Debt	52,146	56,075	63,436	52,771	9,000 I.	61,771	59,717	56,997	54,734	52,338	49,757
Other	11,411	6,812	5,864	11,558	64 J.	11,622	14,928	15,638	15,563	15,546	15,528
Swap Termination Payment	-	-	3,791	-		-	-	-	-	-	-
AFUDC	(408)	(338)	(399)	(865)		(865)	(925)	(984)	(825)	(822)	(813)
Loss From Extinguishment of Debt	5,631	5,457	5,181	5,734		5,734	5,495	5,238	5,001	4,603	4,148
Total Interest	68,780	68,006	77,873	69,198	9,064	78,262	79,215	76,889	74,473	71,665	68,620
NET INCOME	**($16,104)**	**$3,107**	**$17,053**	**$42,550**	**$37,181**	**$79,731**	**$85,268**	**$80,779**	**$75,256**	**$66,508**	**$42,006**

PHILADELPHIA GAS WORKS
CASHFLOW STATEMENT
(Dollars In Thousands)

Rate Increase to fund OPEB Liability	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
SOURCES											
Net Income	($16,104)	$3,107	17,053	$42,550	$37,181	$79,731	$85,268	$80,779	$75,256	$66,508	$42,006
Depreciation & Amortization	44,427	46,660	45,520	46,520	64	46,584	47,805	49,113	50,152	50,967	51,595
Earnings on Restricted Funds	(6,650)	(11,851)	(177)	(4,285)	(3,801)	(8,086)	5,409	5,503	6,696	1,750	227
Elimination of Accrued Interest on Refunded Debt	728	-	-	-		-	-	-	-	-	-
Increased/(Decreased) Other Assets/Liabilities	27,963	25,403	28,649	22,052	(19,340) K.	2,712	(30,633)	(32,969)	(22,052)	(22,259)	(692)
Available From Operations	50,364	63,319	91,045	106,837	14,104	120,941	107,849	102,426	110,052	96,966	93,136
Funds Required for Capital	65,000	70,000	45,000	50,000		50,000	50,000	40,000	25,000	24,878	-
Grant Income	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
FY 2009 Actual Cash Adjustment	-	-	31,649	-		-	-	-	-	-	-
Release of Sinking Fund Asset	6,624	-	-	-		-	-	-	-	-	-
Temporary Financing	-	38,400	-	5,000		5,000	-	-	-	-	-
TOTAL SOURCES	139,988	189,719	185,694	179,837	14,104	193,941	175,849	160,426	153,052	121,844	93,136
USES											
Net Construction Expenditures	70,018	61,742	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Funded Debt Reduction:											
Revenue Bonds	36,675	40,400	41,280	44,480	2,000 L.	46,480	36,284	35,127	45,489	47,494	50,706
Revenue Bond Subordinate Debt	1,370	1,430	1,500	1,565		1,565	1,640	1,715	1,805	1,890	-
FY 2010 Pro Forma Expenditure Adjustment	-	-	-	-		-	(11,000)	-	-	-	-
Equity Bond Contribution/ Debt Reduction	-	-	1,209	-		-	-	-	-	-	18,000
Temporary Financing Repayment	3,400	-	90,000	-	5,000 M.	5,000	-	-	-	-	-
City Loan Repayment/Status	2,000	43,000	-	-		-	-	-	-	-	-
Distribution of Earnings	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	18,000	18,000
Additions To (Reductions of)											
Non-Cash Working Capital	(36,476)	27,507	13,702	7,221	5,356 N.	12,577	(24,648)	3,000	7,287	12,247	8,957
Cash Needs	94,987	192,079	221,282	143,386	12,356	155,742	100,674	143,450	144,324	151,101	166,400
Cash Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	1,748	38,199	75,175	16,976	8,728	(29,257)	(73,264)
TOTAL USES	139,988	189,719	185,694	179,837	14,104	193,941	175,849	160,426	153,052	121,844	93,136
Cash - Beginning of Period	6,697	51,698	49,338	13,750		13,750	51,949	127,124	144,100	152,828	123,571
Cash - Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	1,748	38,199	75,175	16,976	8,728	(29,257)	(73,264)
ENDING CASH	**51,698**	**49,338**	**13,750**	**50,201**	**1,748**	**51,949**	**127,124**	**144,100**	**152,828**	**123,571**	**50,307**
Outstanding Commercial Paper	51,600	90,000	-	5,000	-	-	-	-	-	-	-
City Loan Outstanding	43,000	-	-	-		-	-	-	-	-	-
Internally Generated Funds	-	-	-	22,120	-	22,120	30,398	45,608	46,743	46,592	70,737

PHILADELPHIA GAS WORKS
DEBT SERVICE COVERAGE
(Dollars in Thousands)

Rate Increase to fund OPEB Liability	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
FUNDS PROVIDED											
Total Gas Revenues	$840,105	$831,428	$920,795	$821,323	42,971	864,294	$913,434	$938,633	$950,367	$967,480	$955,763
Other Operating Revenues	19,246	18,199	19,298	18,086	484	18,570	19,543	20,019	20,342	20,727	20,791
Total Operating Revenues	859,351	849,627	940,093	839,409	43,455	882,864	932,977	958,652	970,709	988,207	976,554
Other Income Incr. / (Decr.) Restricted Funds	6,423	3,881	9,608	4,933		4,933	17,708	18,058	18,408	13,249	11,109
City Grant	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
Restricted OPEB Funding Revenues					(42,500) O.	(42,500)	(39,000)	(35,500)	(32,000)	(28,000)	(7,000)
AFUDC (Interest)	408	338	399	865		865	925	984	825	822	813
TOTAL FUNDS PROVIDED	884,182	871,846	968,100	863,207	955	864,162	930,610	960,194	975,942	974,278	981,476
FUNDS APPLIED											
Fuel Costs	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
Other Operating Costs	280,448	282,270	307,981	316,803	1,011	317,814	317,252	319,366	321,166	326,240	331,612
Total Operating Expenses	819,748	794,246	854,952	736,879	1,011	737,890	780,793	813,539	832,692	861,533	876,810
Less: Non-Cash Expenses	66,246	68,898	69,034	68,818	1,682	70,500	66,535	64,854	62,702	60,218	57,275
TOTAL FUNDS APPLIED	753,502	725,348	785,918	668,061	(671)	667,390	714,258	748,685	769,990	801,315	819,535
Funds Available to Cover Debt Service	130,680	146,498	182,182	195,146	1,626	196,772	216,352	211,509	205,952	172,963	161,941
1975 Ordinance Bonds Debt Service	35,359	34,225	32,313	30,101		30,101	30,691	32,110	30,521	28,963	27,261
Debt Service Coverage 1975 Bonds	**3.70**	**4.28**	**5.64**	**6.48**		**6.54**	**7.05**	**6.59**	**6.75**	**5.97**	**5.94**
Net Available after Prior Debt Service	95,321	112,273	149,869	165,045	1,626	166,671	185,661	179,399	175,431	144,000	134,680
Other Capital Leases	-	-	-	-		-	-	-	-	-	-
Net Available after Prior Capital Leases	95,321	112,273	149,869	165,045	1,626	166,671	185,661	179,399	175,431	144,000	134,680
1998 Ordinance Bonds Debt Service	47,611	59,695	70,995	65,439		65,439	68,290	71,040	70,034	71,290	73,686
New Proposed Bond Debt Service	-	-	-	-	11,000 P.	11,000	-	-	-	-	-
Total New Debt Service	47,611	59,695	70,995	65,439	11,000	76,439	68,290	71,040	70,034	71,290	73,686
Debt Service Coverage 1998 Bonds	**2.00**	**1.88**	**2.11**	**2.52**		**2.18**	**2.72**	**2.53**	**2.50**	**2.02**	**1.83**
Net Available after 1998 Debt Service	47,710	52,578	78,874	99,606	(9,374)	90,232	117,371	108,359	105,397	72,710	60,994
1998 Ordinance Subordinate Bond Debt Service	1,987	1,986	1,990	1,986		1,986	1,986	1,984	1,990	1,985	-
Debt Service Coverage Subordinate Bonds	**24.01**	**26.47**	**39.64**	**50.15**		**45.43**	**59.10**	**54.62**	**52.96**	**36.63**	-
Net Available To Service Aggregate Debt Service	**115,885**	**136,809**	**159,895**	**176,443**	5,427	**181,870**	**187,424**	**182,254**	**175,317**	**165,179**	**155,322**
Aggregrate Debt Service Including TXCP	**93,055**	**100,005**	**108,301**	**100,521**	11,000	**111,521**	**107,312**	**112,224**	**109,635**	**109,328**	**108,037**
Fixed Coverage Charge	**1.25**	**1.37**	**1.48**	**1.76**	(0.13)	**1.63**	**1.75**	**1.62**	**1.60**	**1.51**	**1.44**
Fixed Coverage Charge Including $18.0 City Fee	**1.04**	**1.16**	**1.27**	**1.49**	0.23	**1.40**	**1.50**	**1.40**	**1.37**	**1.30**	**1.23**

PHILADELPHIA GAS WORKS
BALANCE SHEET
(Dollars in Thousands)

Rate Increase To fund OPEB Liability	ACTUAL 8/31/07	ACTUAL 8/31/08	ESTIMATE 8/31/09	BUDGET 8/31/10	Pro Forma Adjustments	Adjusted BUDGET 8/31/10	FORECAST 8/31/11	FORECAST 8/31/12	FORECAST 8/31/13	FORECAST 8/31/14	FORECAST 8/31/15
ASSETS											
Utility Plant Net	$1,040,373	$1,062,095	$1,078,406	$1,110,117		$1,110,117	$1,148,608	$1,190,710	$1,217,595	$1,242,977	$1,266,526
Sinking Fund Reserve	102,438	106,198	109,285	112,609	11,489	124,098	120,575	117,988	115,295	114,992	114,677
Capital Improvement Fund	172,134	111,207	63,326	14,289	139,912	154,201	98,459	55,476	26,403	-	-
Restricted Investment Workers' Compensation Fund											
& City of Philadelphia	2,567	2,383	2,594	2,634		2,634	2,687	2,755	2,824	2,910	2,999
Debt Reduction Funding	-	-	-	-		-	-	-	-	-	-
Cash	51,698	49,338	13,750	50,201	1,748	51,949	127,124	144,100	152,828	123,571	50,307
Gas	226,529	222,880	235,582	225,165	2,617	227,782	220,163	212,426	208,320	207,648	208,617
Other	2,245	8,714	9,150	9,425		9,425	3,550	3,450	3,350	3,250	3,150
Accrued Gas Revenues	10,075	8,145	8,741	7,704	471	8,175	9,106	9,434	9,600	9,831	9,733
Reserve for Uncollectible	(150,231)	(140,435)	(137,820)	(133,619)	(484)	(134,103)	(128,831)	(122,639)	(116,160)	(110,017)	(104,497)
Accounts Receivable:	88,618	99,304	115,653	108,675	2,604	111,279	103,988	102,671	105,110	110,712	117,003
Materials & Supplies	147,770	187,539	134,922	127,758		127,758	129,859	136,735	143,770	151,744	154,624
Other Current Assets	2,437	2,317	5,989	6,296		6,296	6,427	6,555	6,686	6,819	6,955
Deferred Debits	3,178	3,309	7,317	8,190	2,752	10,942	3,742	2,942	2,586	2,277	2,227
Unamortized Bond Issuance Expense	42,086	38,738	27,469	24,961	1,460	26,421	24,059	21,751	19,575	17,531	15,626
Unamortized Extraordinary Loss	53,359	47,902	53,742	47,391		47,391	41,896	36,659	31,658	27,054	22,906
Deferred Environmental	4,847	12,650	12,961	12,961		12,961	12,961	12,961	12,961	12,961	12,961
FY 2009 Actual Cash Adjustment			(31,649)	(31,649)		(31,649)	(31,649)	(31,649)	(31,649)	(31,649)	(31,649)
Other Assets	3,435	6,685	3,828	2,163		2,163	1,892	1,624	1,463	1,484	1,508
TOTAL ASSETS	1,714,940	1,729,665	1,597,593	1,596,596	159,965	1,756,561	1,790,628	1,801,278	1,807,105	1,783,383	1,736,670
EQUITY & LIABILITIES											
City Equity	223,301	226,408	243,461	286,011	37,181	323,192	408,460	489,239	564,495	613,003	637,009
Revenue Bonds	1,204,285	1,162,455	1,121,345	1,075,300	148,000	1,223,300	1,187,376	1,150,534	1,103,330	1,053,946	1,003,240
TECA Accretions	13,913	15,314	16,818	18,434		18,434	10,933	-	-	Debt Reduction	(18,000)
Unamortized Discount	(5,462)	(4,951)	(3,719)	(3,323)	(876)	(4,199)	(3,850)	(3,500)	(3,190)	(2,895)	(2,616)
Unamortized Premium	33,051	30,375	28,221	24,961		24,961	23,322	21,033	18,839	16,777	14,851
Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	997,475
Notes Payable	51,600	90,000	-	5,000	(5,000)	-	-	-	-	-	-
City Loan	43,000	-	-								
Accounts Payable	60,615	67,508	38,645	37,250		37,250	47,816	49,336	51,430	52,003	52,370
Customer Deposits	9,049	7,325	3,250	3,350		3,350	3,750	4,000	4,250	4,500	4,750
Other Current Liabilities	4,162	8,264	1,145	1,174		1,174	1,748	1,896	2,050	2,805	2,937
Deferred Credits	11,362	24,317	23,883	4,997		4,997	2,983	1,836	1,714	1,690	1,681
Accrued Interest	12,290	12,391	11,000	10,675		10,675	14,848	14,486	13,970	13,465	12,980
Accrued Taxes & Wages	2,798	3,430	3,021	3,315		3,315	3,380	3,482	3,585	3,689	3,734
Accrued Distribution to City	3,000	3,000	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
Other Liabilities	47,976	83,829	107,523	126,452	(19,340)	107,112	86,862	65,936	43,632	21,400	20,734
TOTAL EQUITY & LIABILITIES	1,714,940	1,729,665	1,597,593	1,596,596	159,965	1,756,561	1,790,628	1,801,278	1,807,105	1,783,383	1,736,670

CAPITALIZATION	ACTUAL FY2007	ACTUAL FY2008	ESTIMATE FY2009	BUDGET FY2010	Pro Forma Adjustments	Adjusted BUDGET 8/31/10	FORECAST FY2011	FORECAST FY2012	FORECAST FY2013	FORECAST FY2014	FORECAST FY2015
Total Capitalization	1,469,088	1,429,601	1,406,126	1,401,383	143,016	1,585,688	1,626,241	1,657,306	1,683,474	1,680,831	1,634,484
Total Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	997,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796		0.796	0.749	0.705	0.665	0.635	0.610
Capitalization Ratio	5.58	5.31	4.78	3.90		3.91	2.98	2.39	1.98	1.74	1.57
Total Capitalization Excluding Leases	1,469,088	1,429,601	1,406,126	1,401,383			1,626,241	1,657,306	1,683,474	1,680,831	1,634,484
Total Long Term Debt Excluding Leases	1,245,787	1,203,193	1,162,665	1,115,372			1,217,781	1,168,067	1,118,979	1,067,828	997,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796			0.75	0.70	0.66	0.64	0.61
Plant in Service	1,620,791	1,681,313	1,732,562	1,788,153		1,788,153	1,860,273	1,940,671	2,026,279	2,098,022	2,169,492
Capital - 106&107	60,522	51,249	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Total Plant	1,681,313	1,732,562	1,788,153	1,860,273		1,860,273	1,940,671	2,026,279	2,098,022	2,169,492	2,240,229
Accumulated Depreciation	(640,940)	(670,467)	(709,747)	(750,156)		(750,156)	(792,063)	(835,569)	(880,427)	(926,515)	(973,703)
Net Utility Plant	1,040,373	1,062,095	1,078,406	1,110,117		1,110,117	1,148,608	1,190,710	1,217,595	1,242,977	1,266,526

PHILADELPHIA GAS WORKS

FISCAL YEAR 2010
OPERATING BUDGET ADJUSTMENTS

Rate Increase to fund OPEB Liability

STATEMENT OF INCOME

A. **Proposed Base Rate $42,500,000**

The increase will begin funding of PGW's post employment benefits liability. This funding includes the prospective annual liability and the funding of the existing reported liability.

B. **Unbilled Adjustment $471,000**

The added revenues reflect the impact of billing the $42.5 million rate increase.

C. **Other Operating Revenues $484,000**

The added revenues reflect the impact of billing the $42.5 million rate increase.

D. **Bad Debt Expense $484,000**

The additional expense represents the impact on customer accounts receivable balances and ultimately the bad debt expense required for the reserve for uncollectible accounts.

E. **Administrative & General ($1,000,000)**

The $1.0 million reduction in Administrative & General costs reflects the elimination of anticipated expenditures in preparation for a work stoppage in May 2010.

F. **BT Supply Chain Initiation ($155,000)**

The net benefit of $.2 million reflects the implementation of the Business Transformation Initiative related to Supply Chain activities. The initiative is expected to cost $4.1 million which was amortized over a three year period at $1.376 million annually. Also, a three year benefit stream of $4.6 million was annualized resulting in a reduction of $1.5 million.

G. **Other Post Employment Benefits $1,682,000**

The added expense reflects the most recent actuarially computed annual liability for PGW's post employment benefits.

H. **Other Income $3,801,000**

The $3.8 million increase in Other Income reflects the pro-forma inclusion of a projected $150.0 million new money bond issue with the requisite sinking fund and capital improvement fund deposits. These funds would earn interest from the time of the sale.

I. **Long-Term Debt Interest $9,000,000**

The $9.0 million increase in long-term debt interest reflects the pro-forma inclusion of annual interest cost at 6%.

J. **Other Interest $64,000**

The $.1 million rise in other interest costs reflects bond discount and issuance costs related to the $150.0 million bond sale.

CASHFLOW STATEMENT

K. **Sources – Other Assets/Liabilities ($19,340,000)**

This reduction primarily reflects the annual $21.0 million decline in the amortization of the $105.1 million existing liability for PGW's post employment benefits.

L. **Uses – Revenue Bonds $2,000,000**

The $2.0 million increase in revenue bond debt service represents the payment of principal on the proposed bond sale.

M. **Uses – Temporary Financing Repayment $5,000,000**

This use of cash reflects the repayment of outstanding commercial paper.

N. **Uses – Non-Cash Working Capital $5,356,000**

The $5.4 million increase in working capital requirements represents the amortization of the $4.1 million Supply Chain Initiative cost over a three year period at $1.376 million annually. In addition, the impact of the $42.5 million rate increase on customer accounts receivable balances, the unbilled gas adjustment, and reserve for uncollectible accounts results in this working capital requirement.

DEBT SERVICE COVERAGE

O. **Restricted OPEB Funding Revenues ($42,500,000)**

The restricted use of the $42.5 million rate increase reflects the funding of PGW's post employment benefits. The rate increase has no impact on debt service coverage requirements.

P. <u>New Proposed Bond Debt Service $11,000,000</u>

The $11.0 million increase in 1998 Ordinance revenue bond deb t service reflects the interest and principal payments on the proposed $150.0 million new bond sale.

PHILADELPHIA GAS WORKS
STATEMENT OF INCOME
(Dollars In Thousands)

OPEB Funding at Existing Rates

	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
OPERATING REVENUES											
Non-Heating	$91,131	$78,687	$66,596	$50,190		$50,190	$49,736	$48,355	$46,752	$45,600	$43,377
Gas Transport Service	12,949	19,215	25,358	30,084		30,084	32,145	34,294	35,759	36,864	37,777
Heating	732,084	723,535	828,245	742,086		742,086	791,622	820,156	835,690	856,785	867,707
Proposed Base Rate	-	-	-	-							
Weather Normalization Adjustment	6,438	11,922	-	-			-	-	-	-	-
Unbilled Adjustment	(2,497)	(1,931)	596	(1,037)		(1,037)	970	366	205	275	135
Total Gas Revenues	840,105	831,428	920,795	821,323		821,323	874,473	903,171	918,406	939,524	948,996
Appliance Repair & Other Revenues	9,398	8,607	8,745	8,972		8,972	9,151	9,334	9,521	9,712	9,906
Other Operating Revenues	9,848	9,592	10,553	9,114		9,114	9,947	10,281	10,456	10,696	10,806
Total Other Operating Revenues	19,246	18,199	19,298	18,086		18,086	19,098	19,615	19,977	20,408	20,712
Total Operating Revenues	859,351	849,627	940,093	839,409		839,409	893,571	922,786	938,383	959,932	969,708
OPERATING EXPENSES											
Natural Gas	539,296	511,938	546,951	420,056		420,056	463,521	494,153	511,506	535,273	545,178
Other Raw Material	4	38	20	20		20	20	20	20	20	20
Sub-Total Fuel	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
CONTRIBUTION MARGINS	**320,051**	**337,651**	**393,122**	**419,333**		**419,333**	**430,030**	**428,613**	**426,857**	**424,639**	**424,510**
Gas Processing	16,240	14,436	16,584	14,297		14,297	14,721	15,743	15,857	16,495	17,212
Field Services	36,100	37,126	36,121	34,682		34,682	35,815	36,829	37,816	38,919	39,921
Distribution	17,119	17,319	20,779	19,889		19,889	20,335	20,814	21,352	21,926	22,635
Collection	8,157	8,441	9,122	9,446		9,446	9,686	9,883	10,181	10,510	10,870
Customer Service	11,783	12,305	13,470	14,410		14,410	14,673	14,963	15,282	15,657	16,064
Account Management	7,064	7,006	7,480	7,879		7,879	7,974	8,118	8,290	8,581	8,835
Bad Debt Expense	40,000	37,000	47,111	43,399		43,399	39,985	37,698	36,136	35,241	34,825
Marketing	2,418	2,628	3,652	4,536		4,536	4,056	4,062	4,066	4,138	4,210
Administrative & General	38,846	44,001	44,773	52,615	(1,000) A.	51,615	50,014	50,530	51,033	51,512	52,362
Health Insurance	36,111	34,226	37,300	41,139		41,139	46,926	51,377	56,234	61,730	67,964
Capitalized Fringe Benefits	(10,449)	(10,331)	(9,214)	(10,572)		(10,572)	(12,225)	(13,024)	(13,617)	(14,266)	(15,009)
Capitalized Administrative Charges	(7,689)	(7,180)	(6,731)	(7,181)		(7,181)	(7,618)	(8,143)	(7,714)	(7,686)	(7,674)
BT Supply Chain Initiative	-	-	-	-	(155) B.	(155)	2,184	758	(1,979)	(2,614)	(3,251)
Pensions	15,217	14,258	15,531	24,062		24,062	23,805	23,533	23,279	23,022	22,692
Taxes	6,730	5,677	6,609	6,875		6,875	7,019	7,165	7,313	7,455	7,603
Other Post Employment Benefits	26,421	25,834	25,952	25,223	1,682 C.	26,905	21,507	18,227	14,713	10,968	6,949
BT Lite Costs/(Benefits)	-	-	3,000	-			-	-	-	-	-
Cost / Labor Savings	-	-	(1,419)	(2,503)		(2,503)	(1,957)	(1,202)	(561)	(230)	(235)
Sub-Total Other Oper.& Maintenance	244,068	242,746	270,120	278,196	527	278,723	276,900	277,331	277,681	281,358	285,973
Depreciation	37,166	40,021	39,280	40,409		40,409	41,907	43,506	44,858	46,088	47,188
Cost of Removal	2,542	2,847	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
To Clearing Accounts	(3,328)	(3,344)	(4,419)	(4,802)		(4,802)	(5,398)	(5,631)	(5,808)	(5,872)	(6,254)
	36,380	39,524	37,861	38,607		38,607	39,509	40,875	42,050	43,216	43,934
Sub-Total Other Oper. & Maint. & Depreciatio	280,448	282,270	307,981	316,803	527	317,330	316,409	318,206	319,731	324,574	329,907
TOTAL OPERATING EXPENSES	819,748	794,246	854,952	736,879	527	737,406	779,950	812,379	831,257	859,867	875,105
OPERATING INCOME	39,603	55,381	85,141	102,530	(527)	102,003	113,621	110,407	107,126	100,065	94,603
Other Income	13,073	15,732	9,785	9,218	3,801 D.	13,019	12,299	12,555	11,712	11,499	10,882
INCOME BEFORE INTEREST	52,676	71,113	94,926	111,748	3,274	115,022	125,920	122,962	118,838	111,564	105,485
INTEREST											
Long-Term Debt	52,146	56,075	63,436	52,771	9,000 E.	61,771	59,717	56,997	54,734	52,338	49,757
Other	11,411	6,812	5,864	11,558	64 F.	11,622	14,928	15,638	15,563	15,546	15,528
Swap Termination Payment	-	-	3,791	-			-	-	-	-	-
AFUDC	(408)	(338)	(399)	(865)		(865)	(925)	(984)	(825)	(822)	(813)
Loss From Extinguishment of Debt	5,631	5,457	5,181	5,734		5,734	5,495	5,238	5,001	4,603	4,148
Total Interest	68,780	68,006	77,873	69,198	9,064	78,262	79,215	76,889	74,473	71,665	68,620
NET INCOME	**($16,104)**	**$3,107**	**$17,053**	**$42,550**	**($5,790)**	**$36,760**	**$46,705**	**$46,073**	**$44,365**	**$39,899**	**$36,865**

PHILADELPHIA GAS WORKS
CASHFLOW STATEMENT
(Dollars in Thousands)

OPEB Funding at Existing Rates	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
SOURCES											
Net Income	($16,104)	$3,107	17,053	$42,550	($5,790)	$36,760	$46,705	$46,073	$44,365	$39,899	$36,865
Depreciation & Amortization	44,427	46,660	45,520	46,520	64	46,584	47,805	49,113	50,152	50,967	51,595
Earnings on Restricted Funds	(6,650)	(11,851)	(177)	(4,285)	(3,801)	(8,086)	5,409	5,503	6,696	1,750	227
Elimination of Accrued Interest on Refunded Debt	728	-	-	-			-	-	-	-	-
Increased/(Decreased) Other Assets/Liabilities	27,963	25,403	28,649	22,052	(19,340)	2,712	(30,633)	(32,969)	(22,052)	(22,259)	(692)
Available From Operations	50,364	63,319	91,045	106,837	(28,867)	77,970	69,286	67,720	79,161	70,357	87,995
Funds Required for Capital	65,000	70,000	45,000	50,000		50,000	50,000	40,000	25,000	24,878	-
Grant Income	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
FY 2009 Actual Cash Adjustment			31,649								
Release of Sinking Fund Asset	6,624	-	-	-							-
Temporary Financing	-	38,400	-	5,000	34,000 G.	39,000	-	17,000	22,000	56,000	54,000
TOTAL SOURCES	139,988	189,719	185,694	179,837	5,133	184,970	137,286	142,720	144,161	151,235	141,995
USES											
Net Construction Expenditures	70,018	61,742	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Funded Debt Reduction:											
Revenue Bonds	36,675	40,400	41,280	44,480	2,000 H.	46,480	36,284	35,127	45,489	47,494	50,706
Revenue Bond Subordinate Debt	1,370	1,430	1,500	1,565		1,565	1,640	1,715	1,805	1,890	-
FY 2010 Pro Forma Expenditure Adjustment							(11,000)				
Equity Bond Contribution/ Debt Reduction	-	-	1,209	-			-	-	-	-	-
Temporary Financing Repayment	3,400	-	90,000	-			38,000	-	-	-	-
City Loan Repayment/Status	2,000	43,000	-	-			-	-	-	-	-
Distribution of Earnings	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	18,000	18,000
Additions To (Reductions of)											
Non-Cash Working Capital	(36,476)	27,507	13,702	7,221	2,752 I.	9,973	(25,769)	2,375	7,118	12,521	10,534
Cash Needs	94,987	192,079	221,282	143,386	4,752	148,138	137,553	142,825	144,155	151,375	149,977
Cash Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	381	36,832	(267)	(105)	6	(140)	(7,982)
TOTAL USES	139,988	189,719	185,694	179,837	5,133	184,970	137,286	142,720	144,161	151,235	141,995
Cash - Beginning of Period	6,697	51,698	49,338	13,750		13,750	50,582	50,315	50,210	50,216	50,076
Cash - Surplus (Shortfall)	45,001	(2,360)	(35,588)	36,451	381	36,832	(267)	(105)	6	(140)	(7,982)
ENDING CASH	**51,698**	**49,338**	**13,750**	**50,201**	**381**	**50,582**	**50,315**	**50,210**	**50,216**	**50,076**	**42,094**
Outstanding Commercial Paper	51,600	90,000	-	5,000		39,000	1,000	18,000	40,000	96,000	150,000
City Loan Outstanding	43,000	-	-	-		-	-	-	-	-	-
Internally Generated Funds	-	-	-	22,120		22,120	30,398	45,608	46,743	46,592	70,737

PHILADELPHIA GAS WORKS
DEBT SERVICE COVERAGE
(Dollars in Thousands)

OPEB Funding at Existing Rates	ACTUAL 2006-07	ACTUAL 2007-08	ESTIMATE 2008-09	BUDGET 2009-10	Pro Forma Adjustments	Adjusted BUDGET 2009-10	FORECAST 2010-11	FORECAST 2011-12	FORECAST 2012-13	FORECAST 2013-14	FORECAST 2014-15
FUNDS PROVIDED											
Total Gas Revenues	$840,105	$831,428	$920,795	$821,323		821,323	$874,473	$903,171	$918,406	$939,524	$948,996
Other Operating Revenues	19,246	18,199	19,298	18,086		18,086	19,098	19,615	19,977	20,408	20,712
Total Operating Revenues	859,351	849,627	940,093	839,409		839,409	893,571	922,786	938,383	959,932	969,708
Other Income Incr. / (Decr.) Restricted Funds	6,423	3,881	9,608	4,933		4,933	17,708	18,058	18,408	13,249	11,109
City Grant	18,000	18,000	18,000	18,000		18,000	18,000	18,000	18,000	-	-
AFUDC (Interest)	408	338	399	865		865	925	984	825	822	813
TOTAL FUNDS PROVIDED	884,182	871,846	968,100	863,207		863,207	930,204	959,828	975,616	974,003	981,630
FUNDS APPLIED											
Fuel Costs	539,300	511,976	546,971	420,076		420,076	463,541	494,173	511,526	535,293	545,198
Other Operating Costs	280,448	282,270	307,981	316,803	527	317,330	316,409	318,206	319,731	324,574	329,907
Total Operating Expenses	819,748	794,246	854,952	736,879	527	737,406	779,950	812,379	831,257	859,867	875,105
Less: Non-Cash Expenses	66,246	68,898	69,034	68,818	1,682	70,500	66,535	64,854	62,702	60,218	57,275
TOTAL FUNDS APPLIED	753,502	725,348	785,918	668,061	(1,155)	666,906	713,415	747,525	768,555	799,649	817,830
Funds Available to Cover Debt Service	130,680	146,498	182,182	195,146	1,155	196,301	216,789	212,303	207,061	174,354	163,800
1975 Ordinance Bonds Debt Service	35,359	34,225	32,313	30,101		30,101	30,691	32,110	30,521	28,963	27,261
Debt Service Coverage 1975 Bonds	**3.70**	**4.28**	**5.64**	**6.48**		**6.52**	**7.06**	**6.61**	**6.78**	**6.02**	**6.01**
Net Available after Prior Debt Service	95,321	112,273	149,869	165,045	1,155	166,200	186,098	180,193	176,540	145,391	136,539
Other Capital Leases	-	-	-	-		-	-	-	-	-	-
Net Available after Prior Capital Leases	95,321	112,273	149,869	165,045	1,155	166,200	186,098	180,193	176,540	145,391	136,539
1998 Ordinance Bonds Debt Service	47,611	59,695	70,995	65,439		65,439	68,290	71,040	70,034	71,290	73,686
New Proposed Bond Debt Service	-	-	-	-	11,000 J.	11,000	-	-	-	-	-
Total New Debt Service	47,611	59,695	70,995	65,439	11,000	76,439	68,290	71,040	70,034	71,290	73,686
Debt Service Coverage 1998 Bonds	**2.00**	**1.88**	**2.11**	**2.52**		**2.17**	**2.73**	**2.54**	**2.52**	**2.04**	**1.85**
Net Available after 1998 Debt Service	47,710	52,578	78,874	99,606	(9,845)	89,761	117,808	109,153	106,506	74,101	62,853
1998 Ordinance Subordinate Bond Debt Ser	1,987	1,986	1,990	1,986		1,986	1,986	1,984	1,990	1,985	-
Debt Service Coverage Subordinate Bonds	**24.01**	**26.47**	**39.64**	**50.15**		**45.20**	**59.32**	**55.02**	**53.52**	**37.33**	-
Net Available To Service Aggregrate Debt Serv	**115,885**	**136,809**	**159,895**	**176,443**	4,956	**181,399**	**187,861**	**183,048**	**176,426**	**166,570**	**157,181**
Aggregrate Debt Service Including TXCP	**93,055**	**100,005**	**108,301**	**100,521**	11,000	**111,521**	**107,312**	**112,224**	**109,635**	**109,328**	**108,037**
Fixed Coverage Charge	**1.25**	**1.37**	**1.48**	**1.76**	(0.13)	**1.63**	**1.75**	**1.63**	**1.61**	**1.52**	**1.45**
Fixed Coverage Charge Including $18.0 City Fee	**1.04**	**1.16**	**1.27**	**1.49**	(0.09)	**1.40**	**1.50**	**1.41**	**1.38**	**1.31**	**1.25**

PHILADELPHIA GAS WORKS
BALANCE SHEET
(Dollars in Thousands)

OPEB Funding at Existing Rates	ACTUAL 8/31/07	ACTUAL 8/31/08	ESTIMATE 8/31/09	BUDGET 8/31/10	Pro Forma Adjustments	Adjusted BUDGET 8/31/10	FORECAST 8/31/11	FORECAST 8/31/12	FORECAST 8/31/13	FORECAST 8/31/14	FORECAST 8/31/15
ASSETS											
Utility Plant Net	$1,040,373	$1,062,095	$1,078,406	$1,110,117		$1,110,117	$1,148,608	$1,190,710	$1,217,595	$1,242,977	$1,266,526
Sinking Fund Reserve	102,438	106,198	109,285	112,609	11,489	124,098	120,575	117,988	115,295	114,992	114,677
Capital Improvement Fund	172,134	111,207	63,326	14,289	139,912	154,201	98,459	55,476	26,403	-	-
Restricted Investment Workers' Compensation Fund											
& City of Philadelphia	2,567	2,383	2,594	2,634		2,634	2,687	2,755	2,824	2,910	2,999
Debt Reduction Funding	-	-	-	-		-	-	-	-	-	-
Cash	51,698	49,338	13,750	50,201	381	50,582	50,315	50,210	50,216	50,076	42,094
Gas	226,529	222,880	235,582	225,165		225,165	215,543	205,983	200,234	198,126	198,734
Other	2,245	8,714	9,150	9,425		9,425	3,550	3,450	3,350	3,250	3,150
Accrued Gas Revenues	10,075	8,145	8,741	7,704		7,704	8,674	9,040	9,245	9,520	9,655
Reserve for Uncollectible	(150,231)	(140,435)	(137,820)	(133,619)		(133,619)	(127,504)	(120,152)	(112,238)	(104,429)	(97,204)
Accounts Receivable:	88,618	99,304	115,653	108,675		108,675	100,263	98,321	100,591	106,467	114,335
Materials & Supplies	147,770	187,539	134,922	127,758		127,758	129,859	136,735	143,770	151,744	154,624
Other Current Assets	2,437	2,317	5,989	6,296		6,296	6,427	6,555	6,686	6,819	6,955
Deferred Debits	3,178	3,309	7,317	8,190	2,752	10,942	3,742	2,942	2,586	2,277	2,227
Unamortized Bond Issuance Expense	42,086	38,738	27,469	24,961	1,460	26,421	24,059	21,751	19,575	17,531	15,626
Unamortized Extraordinary Loss	53,359	47,902	53,742	47,391		47,391	41,896	36,659	31,658	27,054	22,906
Deferred Environmental	4,847	12,650	12,961	12,961		12,961	12,961	12,961	12,961	12,961	12,961
FY 2009 Actual Cash Adjustment			(31,649)	(31,649)		(31,649)	(31,649)	(31,649)	(31,649)	(31,649)	(31,649)
Other Assets	3,435	6,685	3,828	2,163		2,163	1,892	1,624	1,463	1,484	1,508
TOTAL ASSETS	1,714,940	1,729,665	1,597,593	1,596,596	155,994	1,752,590	1,710,094	1,703,038	1,699,974	1,705,643	1,725,789
EQUITY & LIABILITIES											
City Equity	223,301	226,408	243,461	286,011	(5,790)	280,221	326,926	372,999	417,364	439,263	458,128
Revenue Bonds	1,204,285	1,162,455	1,121,345	1,075,300	148,000	1,223,300	1,187,376	1,150,534	1,103,330	1,053,946	1,003,240
TECA Accretions	13,913	15,314	16,818	18,434		18,434	10,933	-	-	Debt Reduction	-
Unamortized Discount	(5,462)	(4,951)	(3,719)	(3,323)	(876)	(4,199)	(3,850)	(3,500)	(3,190)	(2,895)	(2,616)
Unamortized Premium	33,051	30,375	28,221	24,961		24,961	23,322	21,033	18,839	16,777	14,851
Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	1,015,475
Notes Payable	51,600	90,000	-	5,000	34,000	39,000	1,000	18,000	40,000	96,000	150,000
City Loan	43,000	-	-								
Accounts Payable	60,615	67,508	38,645	37,250		37,250	47,816	49,336	51,430	52,003	52,370
Customer Deposits	9,049	7,325	3,250	3,350		3,350	3,750	4,000	4,250	4,500	4,750
Other Current Liabilities	4,162	8,264	1,145	1,174		1,174	1,748	1,896	2,050	2,805	2,937
Deferred Credits	11,362	24,317	23,883	4,997		4,997	2,983	1,836	1,714	1,690	1,681
Accrued Interest	12,290	12,391	11,000	10,675		10,675	14,848	14,486	13,970	13,465	12,980
Accrued Taxes & Wages	2,798	3,430	3,021	3,315		3,315	3,380	3,482	3,585	3,689	3,734
Accrued Distribution to City	3,000	3,000	3,000	3,000		3,000	3,000	3,000	3,000	3,000	3,000
Other Liabilities	47,976	83,829	107,523	126,452	(19,340)	107,112	86,862	65,936	43,632	21,400	20,734
TOTAL EQUITY & LIABILITIES	1,714,940	1,729,665	1,597,593	1,596,596	155,994	1,752,590	1,710,094	1,703,038	1,699,974	1,705,643	1,725,789

CAPITALIZATION	ACTUAL FY2007	ACTUAL FY2008	ESTIMATE FY2009	- BUDGET FY2010	Pro Forma Adjustments	Adjusted BUDGET 8/31/10	FORECAST FY2011	FORECAST FY2012	FORECAST FY2013	FORECAST FY2014	FORECAST FY2015
Total Capitalization	1,469,088	1,429,601	1,406,126	1,401,383	143,016	1,542,717	1,544,707	1,541,066	1,536,343	1,507,091	1,473,603
Total Long Term Debt	1,245,787	1,203,193	1,162,665	1,115,372	147,124	1,262,496	1,217,781	1,168,067	1,118,979	1,067,828	1,015,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796		0.818	0.788	0.758	0.728	0.709	0.689
Capitalization Ratio	5.58	5.31	4.78	3.90		4.51	3.72	3.13	2.68	2.43	2.22
Total Capitalization Excluding Leases	1,469,088	1,429,601	1,406,126	1,401,383			1,544,707	1,541,066	1,536,343	1,507,091	1,473,603
Total Long Term Debt Excluding Leases	1,245,787	1,203,193	1,162,665	1,115,372			1,217,781	1,168,067	1,118,979	1,067,828	1,015,475
Debt to Equity Ratio	0.848	0.842	0.827	0.796			0.79	0.76	0.73	0.71	0.69
Plant in Service	1,620,791	1,681,313	1,732,562	1,788,153		1,788,153	1,860,273	1,940,671	2,026,279	2,098,022	2,169,492
Capital - 106&107	60,522	51,249	55,591	72,120		72,120	80,398	85,608	71,743	71,470	70,737
Total Plant	1,681,313	1,732,562	1,788,153	1,860,273		1,860,273	1,940,671	2,026,279	2,098,022	2,169,492	2,240,229
Accumulated Depreciation	(640,940)	(670,467)	(709,747)	(750,156)		(750,156)	(792,063)	(835,569)	(880,427)	(926,515)	(973,703)
Net Utility Plant	1,040,373	1,062,095	1,078,406	1,110,117		1,110,117	1,148,608	1,190,710	1,217,595	1,242,977	1,266,526

PHILADELPHIA GAS WORKS

FISCAL YEAR 2010
OPERATING BUDGET ADJUSTMENTS

OPEB Funding at Existing Rates

STATEMENT OF INCOME

A. Administrative & General (\$1,000,000)

The \$1.0 million reduction in Administrative & General costs reflects the elimination of anticipated expenditures in preparation for a work stoppage in May 2010.

B. BT Supply Chain Initiation (\$155,000)

The net benefit of \$.2 million reflects the implementation of the Business Transformation Initiative related to Supply Chain activities. The initiative is expected to cost \$4.1 million which was amortized over a three year period at \$1.376 million annually. Also, a three year benefit stream of \$4.6 million was annualized resulting in a reduction of \$1.5 million.

C. Other Post Employment Benefits \$1,682,000

The added expense reflects the most recent actuarially computed annual liability for PGW's post employment benefits.

D. Other Income \$3,801,000

The \$3.8 million increase in Other Income reflects the pro-forma inclusion of a projected \$150.0 million new money bond issue with the requisite sinking fund and capital improvement fund deposits. These funds would earn interest from the time of the sale.

E. Long-Term Debt Interest \$9,000,000

The \$9.0 million increase in long-term debt interest reflects the pro-forma inclusion of annual interest cost at 6%.

F. Other Interest \$64,000

The \$.1 million rise in other interest costs reflects bond discount and issuance costs related to the \$150.0 million bond sale.

CASHFLOW STATEMENT

G. Sources - Temporary Financing $34,000,000

The $34.0 million increase in commercial paper notes outstanding results from the interest and principal payments on the proposed bond sale.

H. Uses - Revenue Bonds $2,000,000

The $2.0 million increase in revenue bond debt service represents the payment of principal on the proposed bond sale.

I. Non-Cash Working Capital $2,752,000

The $2.8 million increase in working capital requirements represents the amortization of the $4.1 million Supply Chain Initiative cost over a three year period at $1.376 million annually.

DEBT SERVICE COVERAGE

J. New Proposed Bond Debt Service $11,000,000

The $11.0 million increase in 1998 Ordinance revenue bond debt service reflects the interest and principal payments on the proposed $150.0 million new bond sale.

In The Matter Of:

PHILADELPHIA GAS WORKS' FISCAL YEAR 2009-2010 OPERATING BUDGET FILING

Filed: June 16, 2009

PHILADELPHIA GAS WORKS
800 WEST MONTGOMERY AVE
PHILADELPHIA, PA 19122

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Exhibit A-1

PHILADELPHIA GAS WORKS
STATEMENT OF INCOME
(Dollars in Thousands)

Line No.		Actual 2007-08	Budget 2008-09	Estimate 2008-09	Budget 2009-10
	OPERATING REVENUES				
1.	Non-Heating	$78,687	$84,369	$66,596	$50,190
2.	Gas Transportation Service	18,900	27,510	25,358	30,084
3.	Heating	723,534	969,765	828,245	742,086
4.	Weather Normalization Adjustment	12,238	-	-	-
5.	Unbilled Gas Adjustment	(1,931)	1,580	596	(1,037)
6.	Total Gas Revenues	831,428	1,083,224	920,795	821,323
7.	Appliance Repair & Other Service Revenues	8,607	9,029	8,745	8,708
8.	Other Operating Revenues	9,592	12,268	10,553	9,114
9.	Total Other Revenues	18,199	21,297	19,298	17,822
10.	Total Operating Revenues	$849,627	$1,104,521	$940,093	$839,145
	OPERATING EXPENSES				
11.	Natural Gas	$511,938	$732,322	$546,951	$420,056
12.	Other Raw Material	38	5	20	20
13.	Sub-Total Fuel	511,976	732,327	546,971	420,076
14.	Contribution Margins	$337,651	$372,194	$393,122	$419,069
15.	Labor & Fringe Benefits	$140,908	$145,530	$149,835	$159,438
16.	Bad Debt Expense	37,000	44,011	47,111	44,757
17.	Other Expenses & Depreciation	104,362	108,360	110,641	94,794
18.	Sub-Total Other O&M & Depreciation	282,270	297,901	307,587	298,989
19.	Total Operating Expenses	$794,246	$1,030,228	$854,558	$719,065
20.	**Operating Income**	$55,381	$74,293	$85,535	$120,080
21.	Other Income	$15,732	$11,526	$9,785	$10,778
22.	Income Before Interest	$71,113	$85,819	$95,320	$130,858
	INTEREST				
23.	Long Term Debt	$56,075	$54,968	$62,449	$59,132
24.	Other Interest	6,812	8,017	6,401	12,480
25.	AFUDC	(338)	(873)	(399)	(865)
26.	Loss from Extinguishment of Debt	5,457	5,102	5,202	5,392
27.	Total Interest Expense	$68,006	$67,214	$73,653	$76,139
28.	Net Earnings	$3,107	$18,605	$21,667	$54,719

PHILADELPHIA GAS WORKS
STATEMENT OF INCOME
(Dollars in Thousands)

Line No.		Actual 2007-08	Budget 2008-09	Estimate 2008-09	Budget 2009-10
	OPERATING REVENUES				
1.	Non-Heating	$78,687	$84,369	$66,596	$50,190
2.	Gas Transportation Service	18,900	27,510	25,358	30,084
3.	Heating	723,534	969,765	828,245	742,086
4.	Weather Normalization Adjustment	12,238	-	-	-
6.	Unbilled Gas Adjustment	(1,931)	1,580	596	(1,037)
7.	Total Gas Revenues	831,428	1,083,224	920,795	821,323
8.	Appliance Repair & Bill Paid Turn-Ons	8,607	9,029	8,745	8,708
9.	Other Operating Revenues	9,592	12,268	10,553	9,114
10.	Total Other Operating Revenues	18,199	21,297	19,298	17,822
11.	**Total Operating Revenues**	$849,627	$1,104,521	$940,093	$839,145
	OPERATING EXPENSES				
12.	Natural Gas	$511,938	732,322	546,951	420,056
13.	Other Raw Material	38	5	20	20
14.	Sub-Total Fuel	511,976	732,327	546,971	420,076
15.	**CONTRIBUTION MARGINS**	$337,651	$372,194	$393,122	$419,069
16.	Gas Processing	14,436	16,265	16,584	14,297
17.	Field Services	37,126	38,375	36,121	34,682
18.	Distribution	17,319	17,982	20,779	19,889
19.	Collection	8,441	9,450	9,122	9,446
20.	Customer Service	12,305	13,510	13,470	14,410
21.	Account Management	7,006	7,548	7,480	7,879
22.	Bad Debt Expense	37,000	44,011	47,111	44,757
23.	Marketing	2,628	4,064	3,652	5,526
24.	Administrative & General	44,001	48,011	44,773	52,745
25.	Health Insurance	34,226	36,551	37,300	39,977
26.	Capitalized Fringe Benefits	(10,331)	(10,592)	(9,214)	(10,528)
27.	Capitalized Administrative Charges	(7,180)	(7,473)	(6,731)	(7,181)
28.	Pensions	14,258	14,419	15,531	21,063
29.	Taxes	5,677	6,799	6,609	6,955
30.	Other Post Employement Benefits	25,834	25,558	25,558	24,615
31.	BT Costs/(Benefits)	-	(1,670)	3,000	(16,700)
32.	Labor/Cost Savings	-	(2,156)	(1,419)	(1,450)
33.	Sub-Total Other Oper.& Maintenance	242,746	260,652	269,726	260,382
34.	Depreciation	40,021	39,408	39,280	40,409
35.	Cost of Removal	2,847	3,000	3,000	3,000
36.	To Clearing Accounts	(3,344)	(5,159)	(4,419)	(4,802)
37.		39,524	37,249	37,861	38,607
38.	Sub-Total Other Oper.& Maint. & Depreciation	282,270	297,901	307,587	298,989
39.	**TOTAL OPERATING EXPENSES**	$794,246	$1,030,228	$854,558	$719,065
40.	**OPERATING INCOME**	55,381	74,293	85,535	120,080
41.	Other Income	15,732	11,526	9,785	10,778
42.	INCOME BEFORE INTEREST	$71,113	$85,819	$95,320	$130,858
	INTEREST				
43.	Long-Term Debt	$56,075	$54,968	$62,449	$59,132
44.	Other	6,812	8,017	6,401	12,480
45.	AFUDC	(338)	(873)	(399)	(865)
46.	Loss From Extinguishment of Debt	5,457	5,102	5,202	5,392
47.	Total Interest	68,006	67,214	73,653	76,139
48.	**NET EARNINGS**	$3,107	$18,605	$21,667	$54,719

Exhibit A-2

PHILADELPHIA GAS WORKS
CASH FLOW STATEMENT
(Dollars in Thousands)

Line No.	SOURCES	Actual 2007-08	Budget 2008-09	Estimate 2008-09	Budget 2009-10
1.	Net Earnings	$3,107	$18,605	$21,667	$54,719
2.	Depreciation & Amortization	46,660	45,626	45,470	46,146
3.	Earnings on Restricted Funds	(11,851)	(4,775)	(5,177)	(5,846)
4.	Elimination of Accrued Interest on Refunded Debt	-	-	-	-
5.	Increased/(Decreased) Other Assets\Liabilities	25,403	(3,928)	28,255	21,444
6.	Available From Operations	63,319	55,528	90,215	116,463
7.	Funds Required for Capital	70,000	70,000	45,000	50,000
8.	Grant Income	18,000	18,000	18,000	18,000
9.	Release of Sinking Fund Asset	-	4,000	-	-
10.	Temporary Financing	38,400	22,000	-	-
11.	**TOTAL SOURCES**	$189,719	$169,528	$153,215	$184,463
	USES				
12.	Net Capital Expenditures	$61,742	$72,745	$55,591	$72,120
	Funded Debt Reduction:				
13.	Revenue Bonds	40,400	43,125	43,125	46,640
14.	Subordinate Revenue Bonds	1,430	1,500	1,500	1,565
15.	Temporary Financing Repayment	-	-	24,000	37,000
16.	City LoanRepayment/Status	43,000	-	-	-
17.	Distribution of Earnings	18,000	18,000	18,000	18,000
	Additions to (Reductions of)				
18.	Non-Cash Working Capital	27,507	34,344	9,645	9,278
19.	Cash Needs	192,079	169,714	151,861	184,603
20.	Cash Surplus (Shortfall)	(2,360)	(186)	1,354	(140)
21.	**TOTAL USES**	$189,719	$169,528	$153,215	$184,463
22.	Cash - Beginning of Period	$51,698	$50,217	$49,338	$50,692
23.	Cash - Surplus (Shortfall)	(2,360)	(186)	1,354	(140)
24.	**Ending Cash**	$49,338	$50,031	$50,692	$50,552
25.	Outstanding Commercial Paper	$90,000	$90,000	$66,000	29,000
26.	City Loan Outstanding	-	-	-	-

Exhibit A-3

PHILADELPHIA GAS WORKS
DEBT SERVICE COVERAGE
(Dollars in Thousands)

Line No.		Actual 2007-08	Budget 2008-09	Estimate 2008-09	Budget 2009-10
	FUNDS PROVIDED				
1.	Total Gas Revenues	$831,428	$1,083,224	$920,795	$821,323
2.	Other Operating Revenues	18,199	21,297	19,298	17,822
3.	Total Operating Revenues	849,627	1,104,521	940,093	839,145
4.	Other Income Less Restricted Funds	3,881	6,751	4,608	4,932
5.	Grant Income	18,000	18,000	18,000	18,000
6.	AFUDC (Interest)	338	873	399	865
7.	**TOTAL FUNDS PROVIDED**	$871,846	$1,130,145	$963,100	$862,942
	FUNDS APPLIED				
8.	Fuel Costs	$511,976	$732,327	$546,971	$420,076
9.	Other Operating Costs	282,270	297,901	307,587	298,989
10.	Total Operating Expenses	794,246	1,030,228	854,558	719,065
11.	Less: Non-Cash Expenses	68,898	68,106	67,883	68,210
12.	**TOTAL FUNDS APPLIED**	$725,348	$962,122	$786,675	$650,855
13.	Funds Available to Cover Debt Service	146,498	168,023	176,425	212,087
14.	1975 Ordinance Bonds Debt Service	$34,225	$32,313	$32,313	$30,101
15.	**Debt Service Coverage 1975 Revenue Bonds**	**4.28**	**5.20**	**5.46**	**7.05**
16.	Net Available After Prior Debt Service	$112,273	$135,710	$144,112	$181,986
17.	1998 Ordinance Bonds Debt Service	$59,695	$64,151	$68,601	$73,261
18.	**Debt Service Coverage 1998 Revenue Bonds**	**1.88**	**2.12**	**2.10**	**2.48**
19.	Net Available After 1998 Debt Service	$52,578	$71,559	$75,511	$108,725
20.	1998 Ordinance Subordinate Bond Debt Service	1,986	1,990	1,990	1,986
21.	**Debt Service Coverage Subordinate Bond**	**26.47**	**35.96**	**37.95**	**54.75**
22.	**Net Available To Service Aggregate Debt Service**	$136,809	$149,499	$159,138	$194,945
23.	**Aggregate Debt Service**	$100,005	$98,454	$105,907	$107,965
24.	**Fixed Coverage Charge on Long Term Debt**	**1.37**	**1.52**	**1.50**	**1.81**
25.	**Fixed Coverage Charge Including $18.0 M City Fee**	**1.16**	**1.28**	**1.28**	**1.55**

Exhibit A-4

PHILADELPHIA GAS WORKS
BALANCE SHEET
(Dollars in Thousands)

Line No.		Actual 8/31/2008	Budget 8/31/2009	Estimate 8/31/2009	Budget 8/31/2010
	ASSETS				
1.	Utility Plant Net	$1,062,095	$1,101,872	$1,078,406	$1,110,117
2.	Sinking Fund Reserve	106,198	104,097	109,285	123,004
3.	Capital Improvement Fund	111,207	41,769	68,326	158,102
4.	Restricted Investment Worker Comp Fund	2,383	2,383	2,594	2,634
5.	Cash	49,338	50,031	50,692	50,552
	Accounts Receivable:				
6.	Gas Receivable	222,880	181,238	235,582	229,280
7.	Other	8,714	250	9,150	9,425
8.	Accrued Gas Revenues	8,145	11,142	8,741	7,704
9.	Reserve for Uncollectible	(140,435)	(126,302)	(137,820)	(134,977)
10.	**Accounts Receivable Net**	**99,304**	**66,328**	**115,653**	**111,432**
11.	Materials & Supplies	187,539	194,743	134,922	127,758
12.	Other Current Assets	2,317	2,505	5,989	6,296
13.	Deferred Debits	3,309	1,479	7,317	8,190
14.	Unamortized Bond Issuance Expense	38,738	35,534	25,842	23,937
15.	Unamortized Extraordinary Loss	47,902	42,800	53,897	48,505
16.	Other Assets	12,650	2,326	12,961	12,961
17.	Deferred Environmental	6,685	2,674	3,828	2,163
18.	**TOTAL ASSETS**	**$1,729,665**	**$1,648,541**	**$1,669,712**	**$1,785,651**
	EQUITY & LIABILITIES				
19.	City Equity	$226,408	$254,833	$248,075	$302,794
	Long Term Debt:				
20.	Revenue Bonds	1,162,455	1,117,830	1,119,785	1,221,580
21.	TECA Accretions	15,314	16,818	16,818	18,434
22.	Unamortized Discount	(4,951)	(4,469)	(5,914)	(6,827)
23.	Unamortized Premium	30,375	27,804	29,875	27,278
24.	Notes Payable	90,000	90,000	66,000	29,000
25.	City Loan	0	-	-	-
	Accounts Payable:				
26.	Natural Gas	67,508	47,529	38,645	37,250
27.	General		14,124		
28.	Customer Deposits	7,325	9,250	3,250	3,350
29.	Other Current Liabilities	8,264	9,100	1,145	1,174
30.	Deferred Credits	24,317	8,406	23,883	4,997
	Accrued Credits:				
31.	Interest	12,391	13,087	15,057	15,432
32.	Taxes & Wages	3,430	5,139	3,021	3,315
33.	Distribution to City	3,000	3,000	3,000	3,000
34.	Other Liabilities	83,829	36,090	107,072	124,874
35.	**TOTAL EQUITY & LIABILITIES**	**$1,729,665**	**$1,648,541**	**$1,669,712**	**$1,785,651**
36.	**Debt to Equity**	**84.2%**	**82.0%**	**82.4%**	**80.6%**

Exhibit B

PHILADELPHIA GAS WORKS
OPERATING REVENUES
(Dollars in Thousands)

Line No.		Actual 2007-08	Estimate 2008-09	Budget 2009-10
1.	Non-Heating	$78,687	$66,596	$50,190
2.	Gas Transportation Service	18,900	25,358	30,084
3.	Heating	723,534	828,245	742,086
4.	Weather Normalization Adjustment	12,238	-	-
5.	Unbilled Gas Adjustment	(1,931)	596	(1,037)
6.	Sub-Total Gas Revenues	831,428	920,795	821,323
7.	Appliance Repair & Other Service Revenues	8,607	8,745	8,708
8.	Other Operating Revenues	9,592	10,553	9,114
9.	Sub-Total Other Revenues	18,199	19,298	17,822
10.	Total Operating Revenues	$849,627	$940,093	$839,145

Exhibit B-1

PHILADELPHIA GAS WORKS
RECONCILIATION OF BILLED REVENUES
(Dollars in Thousands)

Line No.	2007-08 ACTUAL	Billed Revenues	2006-07 GCR Over Recovery	2007-08 GCR Over Recovery	Total Revenues
1.	Firm Non-Heating	$52,529	$443	($964)	$52,008
2.	Interruptible	26,679			26,679
3.	Total Non Heating	79,208	443	(964)	78,687
4.	Gas Transportation Service	18,900			18,900
5.	Heating *	744,179	6,123	(14,530)	735,772
6.	Total Revenues	$842,287	$6,566	($15,494)	$833,359

Line No.	2008-09 ESTIMATE	Billed Revenues	2007-08 GCR Over Recovery	2008-09 GCR Over Recovery	Total Revenues
7.	Firm Non-Heating	$50,980	$964	($1,497)	$50,447
8.	Interruptible	16,149			16,149
9.	Total Non Heating	67,129	964	(1,497)	66,596
10.	Gas Transportation Service	25,358			25,358
11.	Heating	834,230	14,530	($20,515)	828,245
12.	Total Revenues	$926,717	$15,494	($22,012)	$920,199

Line No.	2009-10 BUDGET	Billed Revenues	2008-09 GCR Over Recovery	2009-10 GCR Over/Under Recovery	Total Revenues
13.	Firm Non-Heating	$40,678	$1,497	-	$42,175
14.	Interruptible	8,015			8,015
15.	Total Non Heating	48,693	1,497	-	50,190
16.	Gas Transportation Service	30,084			30,084
17.	Heating	721,571	20,515	-	742,086
18.	Total Revenues	$800,348	$22,012	-	$822,360

* The 2007-2008 fiscal period reflects a $12.2 million WNA charge to customers reflecting the impact of the warmer winter heating season.

Exhibit B-1-1

PHILADELPHIA GAS WORKS
GAS REVENUES
(Dollars in Thousands)

Line No.	NON HEATING	Actual 2007-08	Estimate 2008-09	Budget 2009-10
1.	Residential	$20,165	$18,538	$14,633
2.	CRP Residential	-	921	764
3.	CRP Shortfall	(125)	(459)	(340)
4.	Commercial	25,794	25,422	20,372
5.	Industrial	4,265	4,279	3,282
6.	Municipal	2,424	2,273	1,963
7.	NGV	6	6	4
8.	Total Firm Non-Heating	$52,529	$50,980	$40,678
9.	BPS - Small	$2,642	$2,213	$1,093
10.	BPS - Large	15,493	11,800	5,698
11.	BPS - A/C	-	49	75
12	BPS - H Indirect	-	-	-
13.	LBS-L Direct	-	-	-
14.	LBS-L Indirect	(14)	161	101
15.	LBS-S Indirect	6,605	1,216	733
16.	LBS-XL Direct	264	-	-
17.	LBS-XL Indirect	331	351	243
18.	Co-Generation - Indirect	171	129	72
19.	GTS - Sales	1,187	230	-
20.	Total Interruptibles	26,679	16,149	8,015
21.	Total Non Heating	$79,208	$67,129	$48,693
	HEATING			
22.	Residential	$666,375	$569,149	$488,995
23.	CRP Residential	-	197,104	172,910
24.	CRP Shortfall	(87,603)	(98,211)	(77,028)
25.	Commercial	125,399	134,212	109,902
26.	Industrial	7,609	8,271	6,969
27.	Municipal	9,167	8,936	7,644
28.	Housing Authority	10,994	14,769	12,179
29.	WNA	12,238	-	-
30.	Total Heating	744,179	834,230	721,571
31.	Net Billed Revenues	823,387	901,359	770,264
32.	GTS Revenues	18,900	25,358	30,084
33.	Total Billed Revenues	$842,287	$926,717	$800,348
34.	Degree Days	3,746	4,181	4,412

Exhibit B-2

PHILADELPHIA GAS WORKS
GAS SALES
(MCF's)

Line No.	NON HEATING	Actual 2007-08	Estimated 2008-09	Budget 2009-10
1.	Residential	802	718	653
2.	CRP Residential	-	41	40
3.	Commercial	1,395	1,352	1,315
4.	Industrial	235	228	215
5.	Municipal	153	134	147
6.	Housing Authority	-	-	-
7.	Total Firm Non-Heating	2,585	2,473	2,370
8.	BPS - Small	141	133	94
9.	BPS - Large	923	836	563
10.	BPS - A/C	-	6	10
11.	LBS - L Direct	-	-	-
12.	LBS - L Indirect	1	14	9
13.	LBS - S Indirect	535	101	63
14.	LBS - XL Direct	22	30	-
15.	LBS - XL Indirect	25	-	22
16.	Co-Generation - Indirect	14	13	9
17.	GTS - Sales	130	12	-
18.	Total Interruptibles	1,791	1,145	770
19.	Total Non Heating	4,376	3,618	3,140
	HEATING			
20.	Residential	34,347	27,927	28,794
21.	CRP Residential	-	9,756	10,354
22.	Commercial	6,984	7,141	7,233
23.	Industrial	421	436	455
24.	Municipal	566	515	572
25.	Housing Authority	622	782	803
26.	Total Heating	42,940	46,557	48,211
27.	Net Billed Sales	47,316	50,175	51,351
28.	GTS Volumes	19,032	21,731	22,353
29.	Total Billed Sales	66,348	71,906	73,704
30.	Firm Sales	45,525	49,030	50,581
31.	Residential Sales	35,149	38,442	39,841

Exhibit C-1-1

PHILADELPHIA GAS WORKS
NATURAL GAS EXPENSE
2007-08 ACTUAL
(Dollars in Thousands)

Line No.		Billed	(To) Inventory	From Inventory	Refunds	Seasonal Adjustment	Total
1.	September	$ 32,292	$ (14,786)	$ 554	$ -	$ (4,412)	$ 13,648
2.	October	31,566	(13,925)	751	-	(2,184)	16,208
3.	November	54,048	(7,476)	6,971	-	975	54,518
4.	December	64,694	(2,333)	19,360	-	6,088	87,809
5.	January	56,478	(2,112)	32,860	-	8,545	95,771
6.	February	57,267	(3,278)	25,922	-	6,342	86,253
7.	March	52,224	(2,611)	16,544	-	3,123	69,280
8.	April	37,298	(9,538)	7,802	-	(1,114)	34,448
9.	May	50,294	(21,350)	713	(466)	(3,567)	25,624
10.	June	44,548	(25,373)	564	(3,333)	(4,629)	11,777
11.	July	48,141	(28,603)	607	(3,254)	(4,582)	12,309
12.	August	41,112	(22,304)	(6,323)	(3,607)	(4,585)	4,293
13.	Total	$ 569,962	$ (153,689)	$ 106,325	$ (10,660)	$ -	$ 511,938

Exhibit C-1-2

PHILADELPHIA GAS WORKS
NATURAL GAS EXPENSE
2008-09 ESTIMATE
(Dollars in Thousands)

Line No.		Billed	(To) Inventory	From Inventory	Refunds	Seasonal Adjustment	Total
1.	September	$ 37,041	$ (21,062)	$ 1,640	$ (31)	$ (4,441)	$ 13,147
2.	October	40,736	(13,315)	5,826		(2,076)	31,171
3.	November	53,398	(6,404)	7,335	-	1,077	55,406
4.	December	65,685	(2,847)	33,526	-	6,151	102,515
5.	January	69,058	156	49,018	-	8,157	126,389
6.	February	54,663	(955)	27,950		6,134	87,792
7.	March	52,299	(2,991)	18,759	-	3,646	71,713
8.	April	29,252	(5,923)	2,566	-	(745)	25,150
9.	May	23,904	(8,579)	655	-	(3,523)	12,457
10.	June	19,950	(8,589)	608	-	(4,829)	7,140
11.	July	22,505	(10,875)	629	-	(4,773)	7,486
12.	August	21,540	(10,806)	629	-	(4,778)	6,585
13.	Total	$ 490,031	$ (92,190)	$ 149,141	$ (31)	$ -	$ 546,951

Exhibit C-1-3

PHILADELPHIA GAS WORKS
NATURAL GAS EXPENSE
2009-10 BUDGET
(Dollars in Thousands)

Line No.		Billed	(To) Inventory	From Inventory	Refunds	Seasonal Adjustment	Total
1.	September	$ 26,011	$ (14,220)	$ 606	$ -	$ (4,123)	$ 8,274
2.	October	32,384	(13,272)	713	-	(1,972)	17,853
3.	November	37,601	(4,599)	4,952	-	1,151	39,105
4.	December	48,266	(1,761)	18,988	-	5,577	71,070
5.	January	52,834	-	26,094	-	7,401	86,329
6.	February	47,438	-	19,803	-	5,388	72,629
7.	March	46,490	(3,443)	11,881	-	3,256	58,184
8.	April	33,993	(8,019)	3,966	-	(669)	29,271
9.	May	28,186	(10,250)	592	-	(3,099)	15,429
10.	June	20,924	(8,499)	560	-	(4,361)	8,624
11.	July	20,599	(7,875)	576	-	(4,269)	9,031
12.	August	19,833	(11,872)	576	-	(4,280)	4,257
13.	Total	$ 414,559	$ (83,810)	$ 89,307	$ -	$ -	$ 420,056

Exhibit C-3

PHILADELPHIA GAS WORKS
LABOR & FRINGE BENEFITS
(Dollars in Thousands)

Line No.		Actual 2007-08	Estimate 2008-09	Budget 2009-10
	OPERATING LABOR			
1.	Payroll	$ 105,887	$ 108,962	$ 111,764
2.	To Capital & Clearing Accounts	(20,726)	(20,567)	(22,221)
3.	Total Operating Labor	85,161	88,395	89,543
	PENSIONS			
4.	Beneficiaries	32,839	33,866	35,128
5.	Payments to (Withdrawals from) Fund	(18,581)	(18,335)	(14,065)
6.	Total Pensions	14,258	15,531	21,063
	INSURANCE			
7.	Group Life	1,586	2,000	1,900
8.	Health	34,226	37,300	39,977
9.	Total Insurance	35,812	39,300	41,877
	TAXES			
10.	FICA - OASI	6,484	6,645	6,832
11.	FICA - Medical	1,532	1,578	1,615
12.	State Unemployment	132	175	140
13.	Federal Unemployment	-	-	-
14.	Tax Rebate/Settlements	(903)	(214)	-
15.	Allocated to Capital Projects	(1,568)	(1,575)	(1,632)
16.	Total Taxes	5,677	6,609	6,955
17.	**Total Labor & Fringe Benefits**	$ 140,908	$ 149,835	$ 159,438

Exhibit C-3-1

PHILADELPHIA GAS WORKS
DETAIL OF DIRECT LABOR EXPENSES
(Dollars in Thousands)

Line No.		Actual 2007-08 Average Personnel	Actual 2007-08 Payroll	Estimate 2008-09 Average Personnel	Estimate 2008-09 Payroll	Budget 2009-10 Average Personnel	Budget 2009-10 Payroll
1.	Administration	55	$ 6,120	59	$ 6,070	59	$ 6,067
2.	Finance	43	2,384	43	2,548	43	2,599
3.	Customer Activities	377	19,854	368	20,866	368	21,405
4.	Marketing & Planning	72	4,509	76	4,775	76	5,648
5.	Operations	933	58,390	942	60,319	937	62,000
6.	Systems & Services	231	14,335	234	15,507	239	15,105
7.	Labor Cost Savings	-	-	(22)	(1,419)	(22)	(1,450)
8.	Philadelphia Gas Commission	4	295	5	296	5	390
9.	Total Personnel & Payroll	1,715	$ 105,887	1,705	$ 108,962	1,705	$ 111,764
10.	Allocated to Capital & Clearing Accounts		(20,726)		(20,567)		(22,221)
11.	Net Operating Labor	1,715	$ 85,161	1,705	$ 88,395	1,705	$ 89,543

Exhibit C-4

PHILADELPHIA GAS WORKS
DETAIL OF OTHER EXPENSES
(Dollars in Thousands)

LINE NO.	OTHER EXPENSES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
1.	Appropriation for Reserves and Other Losses	$5,485	$4,559	$3,564
2.	Advertising	$1,638	1,325	2,246
3.	General Material	$7,700	5,074	6,058
4.	Insurance	$3,228	3,350	4,520
5.	Contracted Maintenance	$4,043	5,810	5,911
6.	Utilities	$3,689	3,771	3,845
7.	Rentals	$787	1,472	1,488
8.	Purchased Services	$20,421	22,580	27,083
9.	Postage	$2,313	2,395	2,538
10.	Promotion	$20	50	255
11.	Non-Utility Revenues	($154)	(165)	(165)
12.	Labor Related Fringe Benefits and A&G Charged to Capital	($17,512)	(15,945)	(17,709)
13.	Depreciation	$42,868	42,280	43,409
14.	Less: Cleared to Capital	($583)	(919)	(1,107)
15.	Miscellaneous	$30,418	35,004	12,858
16.	Total Other Expenses	$104,362	$110,641	$94,794

DETAIL OF OTHER OPERATING EXPENSES C-4

APPROPRIATION FOR RESERVE AND OTHER LOSSES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Risk Management	$4,791	$4,265	$3,460
Compensated Absences	633	(409)	44
Corporate Settlements	61	703	60
Grand Total	$5,485	$4,559	$3,564

ADVERTISING	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Field Services	$136	$154	$167
Collection	352	200	350
Marketing	17	368	670
Corporate Communications	744	150	400
VP Customer Affairs	268	308	503
PUC	3	25	25
Organizational Development	78	76	85
Gas Commission	9	9	10
Information Services	-	1	1
Telecommunications	8	11	12
Materials Management	23	23	23
Grand Total	$1,638	$1,325	$2,246

DETAIL OF OTHER OPERATING EXPENSES C-4

GENERAL MATERIAL	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$3,122	$1,201	$1,241
Distribution	1,707	1,453	1,483
Field Services	8,704	8,685	6,016
Collection	236	257	265
Commercial Resource Center	-	1	1
Customer Service	75	89	88
Account Management	315	429	458
Marketing	34	30	47
Corporate Communications	20	23	20
Gas Control & Acquisition	8	4	3
Human Resources	39	32	30
Risk Management	1	2	2
Accounting & Reporting	8	8	8
Treasury	14	12	11
President & CEO	2	3	3
Legal	22	24	24
VP Customer Affairs	31	22	24
COO	4	5	5
Security	4	6	7
VP Reg & External Affairs	2	2	2
Sr VP Finance	4	5	5
Strategic Development	2	-	-
Rates & Gas Planning	4	5	5
Customer Review	5	6	6
Business Transformation	4	4	4
VP Gas Management	1	1	1
VP Corporate Preparedness	18	34	48
Internal Auditing	-	2	2
Sr VP Operations	-	1	1
VP Marketing	1	1	1
VP Supply Chain	1	1	1
VP Technical Compliance	8	26	6
Policies & Compliance	2	1	2
Chemical Laboratory Services	10	10	15
Organization Development	25	30	28
Gas Commission	4	5	5
Utility Gas Use	(6,388)	(6,825)	(3,940)
Emergency Operations	-	-	1,000
Pandemic Disease	-	25	25
Facilities Management	527	581	465
Engineering Services	14	18	13
Information Services	192	198	186
Telecommunications	23	24	26
Fleet Operations	1,616	1,609	1,439
Materials Management	(2,721)	(2,976)	(3,024)
Grand Total	$7,700	$5,074	$6,058

DETAIL OF OTHER OPERATING EXPENSES C-4

INSURANCE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Human Resources	35,812	$39,300	$41,877
Risk Management	3,188	3,305	4,470
Gas Commission	40	45	50
Sub-Total	39,040	42,650	46,397
Less Group Life & Health	35,812	39,300	41,877
Grand Total	$3,228	$3,350	$4,520

CONTRACTED MAINTENANCE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Maintenance Contractors	1,967	$2,981	$3,028
Maintenance Software	1,560	2,096	2,175
Maintenance - Capital	11	45	45
Maintenance Office Equipment	505	688	663
Grand Total	$4,043	$5,810	$5,911

UTILITIES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Electric	$2,120	$2,300	$2,341
Purchased Telephone	1,087	1,080	1,113
Water	482	391	391
Grand Total	$3,689	$3,771	$3,845

RENTALS	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Other Rents	$295	$594	$622
Equipment Rentals & Leasing	492	878	866
Grand Total	$787	$1,472	$1,488

DETAIL OF OTHER OPERATING EXPENSES C-4

MAINTENANCE CONTRACTORS	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$618	$1,720	$1,640
Distribution	778	593	690
Human Resources	3	1	1
Chemical Laboratory Services	10	5	5
Facilities Management	386	452	454
Engineering Services	5	8	7
Information Services	55	63	64
Telecommunications	4	5	5
Fleet Operations	87	109	135
Materials Management	21	25	27
Grand Total	$1,967	$2,981	$3,028

MAINTENANCE - CAPITAL	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	11	45	45
Grand Total	$11	$45	$45

MAINTENANCE SOFTWARE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Distribution	$14	56	$54
Field Services	67	59	60
Customer Service	110	54	55
Gas Control & Acquisition	42	87	87
Risk Management	-	20	31
Rates & Gas Planning	27	26	27
Chemical Laboratory Services	1	-	-
Facilities Management	8	14	16
Engineering Services	7	13	12
Information Services	1,239	1,708	1,758
Telecommunications	12	14	28
Fleet Operations	12	15	16
Materials Management	21	30	31
Grand Total	$1,560	$2,096	$2,175

MAINTENANCE OFFICE EQUIP	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Account Management	-	-	-
Corporate Communications	-	1	1
Legal	-	5	5
Gas Commission	2	2	1
Maintenance Office Equip	-	-	-
Facilities Management	7	9	8
Engineering Services	3	4	3
Information Services	110	252	238
Telecommunications	325	313	306
Fleet Operations	4	6	6
Materials Management	54	96	95
Grand Total	$505	$688	$663

DETAIL OF OTHER OPERATING EXPENSES C-4

ELECTRIC	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$1,010	$1,030	$1,050
Distribution	37	32	34
Facilities Management	855	996	1,009
Engineering Services	12	16	15
Information Services	123	139	143
Telecommunications	10	11	11
Fleet Operations	41	40	42
Materials Management	32	36	37
Grand Total	$2,120	$2,300	$2,341

PURCHASED TELEPHONE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Facilities Management	$18	$21	$22
Engineering Services	6	6	5
Information Services	57	74	73
Telecommunications	975	943	981
Fleet Operations	10	12	11
Materials Management	21	24	21
Grand Total	$1,087	$1,080	$1,113

WATER	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$230	$250	$250
Facilities Management	201	113	114
Engineering Services	3	2	1
Information Services	29	16	16
Telecommunications	2	1	1
Fleet Operations	10	5	5
Materials Management	7	4	4
	$482	$391	$391

DETAIL OF OTHER OPERATING EXPENSES C-4

OTHER RENTS	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Distribution	$5	$7	$8
Customer Service	236	277	290
Gas Commission	48	48	50
Facilities Management	5	211	220
Engineering	-	4	3
Information Services	1	29	31
Telecommunications	-	3	3
Fleet Operations	-	8	9
Material Management	-	7	8
Grand Total	$295	$594	$622

EQUIPMENT RENTALS & LEASING	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$62	$125	$125
Distribution	90	84	84
Field Services	21	17	16
Collection	10	33	41
Customer Service	25	27	74
Account Management	9	9	11
Marketing	17	15	15
Gas Control & Acquisition	-	1	1
Human Resources	31	24	25
Risk Management	7	8	8
Accounting & Reporting	10	8	8
President & CEO	15	15	14
Legal	8	14	14
VP Customer Affairs	5	19	19
Security	6	1	-
VP Reg & External Affairs	-	1	1
Strategic Development	1	-	-
Customer Review	1	4	4
Business Transformation	-	1	1
VP Gas Management	-	1	1
VP Corporate Preparedness	6	6	6
VP Technical Compliance	6	7	7
Chemical Laboratory Services	1	6	6
Gas Commission	1	3	6
Facilities Management	6	10	8
Engineering Services	-	2	3
Information Services	25	24	169
Fleet Operations	91	352	158
Materials Management	38	61	41
Grand Total	$492	$878	$866

DETAIL OF OTHER OPERATING EXPENSES C-4

PURCHASE SERVICES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$624	$692	$575
Distribution	714	556	547
Field Services	621	422	583
Collection	563	425	684
Commercial Resource Center	1	2	1
Customer Service	331	988	887
Account Management	1,501	1,619	1,760
Marketing	97	320	525
Corporate Communications	227	255	300
Gas Control & Acquisition	55	70	70
Human Resources	725	969	960
Risk Management	546	877	877
Accounting & Reporting	10	17	72
Treasury	267	354	426
President & CEO	2	5	5
Legal	183	175	175
VP Customer Affairs	2,808	2,905	3,957
COO	-	1	1
Security	2,222	2,487	2,900
VP Reg & External Affairs	145	200	230
Sr VP Finance	3	5	5
Public Utility Commission	342	288	322
Strategic Development	27	-	-
Rates & Gas Planning	123	121	121
Customer Review	115	121	86
Business Transformation	1,483	620	1,725
VP Gas Management	5	1	1
VP Corporate Preparedness	55	61	101
Internal Auditing	52	349	325
VP Marketing	1	3	4
Operation System Support	-	-	4
VP Supply Chain	1	7	10
VP Technical Compliance	41	45	70
Policies & Compliance	82	35	55
Chemical Laboratory Services	49	67	111
Organization Development	673	642	691
Gas Commission	349	317	385
FERC Matters	124	210	210
Special Legal	235	480	600
Administrative Consultants	1,490	1,163	1,392
LNG Terminal Project	12	-	-
Utility Merger	10	-	-
Facilities Management	454	887	1,270
Engineering Services	340	467	371
Information Services	2,497	3,008	3,293
Telecommunications	13	18	22
Fleet Operations	94	151	183
Materials Management	109	175	191
Grand Total	$20,421	$22,580	$27,083

DETAIL OF OTHER OPERATING EXPENSES C-4

POSTAGE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Distribution	7	4	4
Field Services	136	160	200
Collection	34	133	183
Customer Resource Center	-	7	8
Customer Service	19	32	33
Account Management	1,814	1,813	1,826
Marketing	2	25	40
Corporate Communications	2	2	2
Human Resources	19	20	20
Risk Management	-	1	1
Treasury	14	14	14
President & CEO	-	-	1
Legal	4	5	5
VP Customer Affairs	259	168	190
Customer Review	-	1	1
VP Gas Management	-	1	1
VP Corporate Preparedness	-	1	1
Gas Commission	1	1	1
Metered Mail	-	5	5
Materials Management	2	2	2
Grand Total	$2,313	$2,395	$2,538

PROMOTION	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Marketing	20	50	255
Grand Total	$20	$50	$255

NON-UTILITY REVENUE	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Customer Service	(66)	(74)	(74)
Account Management	(66)	(74)	(74)
Treasury	(16)	-	-
Facilities Management	-	-	-
Engineering Services	-	-	-
Information Services	-	(1)	(1)
Telecommunications	-	(13)	(13)
Fleet Operations	(6)	(3)	(3)
Material Management	-	-	-
Grand Total	($154)	($165)	($165)

DETAIL OF OTHER OPERATING EXPENSES C-4

LABOR RELATED FRINGE BENEFITS & A&G CHARGED TO CAPITAL	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Construction Additive	(10,332)	(9,214)	(10,528)
A & G Overhead	(7,180)	(6,731)	(7,181)
Grand Total	($17,512)	($15,945)	($17,709)

MISCELLANEOUS	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Expense of Employees	$678	$747	$1,116
Dues & Subscriptions	3,667	3,847	4,022
Taxes	21	21	30
PFMC - Management Fee	381	359	360
Deferred Compensation	361	337	344
BT Projects Cost/(Benefits)	-	3,000	(16,700)
Post Retirement Benefits	25,834	25,558	24,615
LNG Inventory	(901)	925	(1,245)
Amortization	377	210	316
Grand Total	$30,418	$35,004	$12,858

DETAIL OF OTHER OPERATING EXPENSES C-4

EXPENSE OF EMPLOYEES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$28	$44	$48
Distribution	59	63	63
Field Services	54	34	49
Collection	9	11	14
Commercial Resource Center	-	2	4
Customer Service	7	45	34
Account Management	-	-	2
Marketing	54	104	251
Corporate Communications	8	10	10
Gas Control & Acquisition	14	42	42
Human Resources	4	15	30
Risk Management	2	4	4
Accounting & Reporting	7	15	18
Treasury	6	10	10
President & CEO	11	9	10
Legal	17	22	22
VP Customer Affairs	36	22	34
COO	13	10	10
Security	5	6	10
VP Reg & External Affairs	2	3	5
Sr VP Finance	12	15	24
Rates & Gas Planning	6	2	10
Customer Review	-	1	1
Business Transformation	6	18	26
VP Gas Management	3	3	3
VP Corporate Preparedness	4	8	11
Internal Auditing	1	4	4
Sr VP Operations	-	-	8
VP Marketing	9	10	12
VP Supply Chain	1	4	7
VP Technical Compliance	10	14	18
Policies & Compliance	12	3	13
Chemical Laboratory Services	2	5	5
Organization Development	11	15	20
Gas Commission	1	2	2
Relocation Expense	17	15	25
Facilities Management	8	14	11
Engineering Services	5	12	11
Information Services	194	97	198
Telecommunications	27	10	7
Fleet Operations	5	9	10
Materials Management	8	15	20
Grand Total	$678	$747	$1,116

DETAIL OF OTHER OPERATING EXPENSES C-4

DUES & SUBSCRIPTIONS	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Processing	$1	$2	$2
Distribution	3	3	3
Field Services	-	1	1
Customer Service	-	1	1
Marketing	30	36	66
Corporate Communications	4	1	1
Gas Control & Acquisition	8	35	35
Human Resources	3	3	3
Risk Management	2	2	2
Accounting & Reporting	1	1	1
Treasury	2	2	2
President & CEO	-	1	1
Legal	32	18	18
VP Customer Affairs	-	1	1
COO	2	2	2
Security	-	2	2
VP Reg & External Affairs	-	1	1
Sr VP Finance	1	3	4
PUC	2,539	2,475	2,601
Strategic Development	1	-	-
Rates & Gas Planning	24	26	27
Business Transformation	1	2	2
VP Gas Management	-	1	1
VP Corporate Preparedness	1	3	4
Internal Auditing	27	31	31
VP Marketing	1	1	1
VP Supply Chain	4	2	2
VP Technical Compliance	8	9	9
Policies & Compliance	-	1	1
Organization Development	272	426	426
Gas Commission	3	4	4
Company Dues & Subscriptions	681	716	731
Facilities Management	1	1	2
Engineering Services	2	5	4
Information Services	3	10	11
Fleet Operations	7	9	9
Materials Management	3	10	10
Grand Total	$3,667	$3,847	$4,022

TAXES	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Gas Commission	$21	$21	$30
Grand Total	$21	$21	$30

DETAIL OF OTHER OPERATING EXPENSES C-4

AMORTIZATION	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Human Resources	$10	-	$29
Accounting & Reporting	68	-	-
Treasury	85	-	29
Public Utility Commission	108	210	258
VP Labor, Safety, Preparedness	10	-	-
Policies & Compliance	31	-	-
Information Services	40	-	-
Materials Management	24	-	-
Grand Total	$377	$210	$316

Exhibit D

PHILADELPHIA GAS WORKS
OTHER INCOME
(Dollars in Thousands)

Line No.		Actual 2007-08	Estimate 2008-09	Budget 2009-10
	Interest Earnings On:			
1.	Capital Improvement Fund	$ 8,089	$ 2,206	$ 2,302
2.	Revenue Bond Sinking Fund	3,587	3,087	3,504
3.	Temporary Investments	1,809	400	700
4.	Natural Gas Refunds	296	-	-
5.	Gain/Loss on Investments	171	-	-
6.	Notes Receivable - Intl House	1		-
	Total Interest Earnings	$ 13,953	$ 5,693	$ 6,506
7.	Miscellaneous Income	$ 877	$ 510	$ 439
8.	Rental Income	57	57	58
9.	Penalties Suppliers Gas Choice	220	400	400
10.	Penalties Regulatory	-	-	-
11.	Guaranteed Investment Contract Proceeds	625	625	625
12.	Capacity Release Sharing	-	2,500	2,750
	Total Other Income	$ 15,732	$ 9,785	$ 10,778

PHILADELPHIA GAS WORKS
REVENUE BOND DEBT SERVICE
(Dollars in Thousands)

Line No.	Year Issued	Series	Actual 2007-08	Estimate 2008-09	Budget 2009-10
	Interest Payments				
1.	1989	11th C TECA	-	-	-
2.	1990	12th A TECA	-	-	-
3.	1994	15th	-	-	-
4.	1999	16th	1,872	1,402	930
5.	2003	17th	8,302	7,816	7,384
6.	2004	18th	2,707	2,622	2,534
7.	2007	19th	634	723	723
8.	1998	1st A	5,572	4,969	4,374
9.	1999	2nd	665	550	429
10.	2001	3rd	680	551	441
11.	2003	4th	4,908	4,805	4,678
12.	2004	5th	6,000	6,000	5,938
13.	2004	5th Variable	824	766	766
14.	2006	6th	11,336	16,231	-
15.	2007	7th Refunding	1,356	1,545	1,545
16.	2007	7th New	8,664	9,809	9,685
17.	2009	8th Refunding	-	-	3,849
18.	2010	9th New	-	-	13,445
19.		Total Interest Payments	$53,520	$57,789	$56,721
	Interest Accruals				
20.	1989	11th C TECA	$1,401	$1,504	$1,615
21.	1990	12th A TECA	-	-	-
22.	1994	15th	-	-	-
23.	1999	16th	1,794	1,324	930
24.	2003	17th	8,221	7,744	7,322
25.	2004	18th	2,700	2,615	2,488
26.	2007	19th	722	722	723
27.	1998	1st A	5,471	4,870	4,281
28.	1999	2nd	646	530	407
29.	2001	3rd	669	542	429
30.	2003	4th	4,900	4,794	4,666
31.	2004	5th	6,000	6,000	5,876
32.	2004	5th Variable	766	766	766
33.	2006	6th	10,824	17,015	-
34.	2006	7th Refunding	1,545	1,545	1,545
35.	2006	7th New	9,871	9,759	9,632
36.	2009	8th Refunding	-	2,241	13,557
37.	2010	9th New	-	-	4,487
38.		Total Interest Accruals	$55,530	$61,971	$58,724

Exhibit E-2

PHILADELPHIA GAS WORKS
OTHER LONG TERM DEBT SERVICE
(Dollars in Thousands)

Line No.	Year Issued	Series	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Interest Payments					
1.	1998	1st C Subordinate	$556	$490	$421
2.	Total Interest Payments		$556	$490	$421
Interest Accruals					
3.	1998	1st C Subordinate	$545	$478	$408
4.	Total Interest Accruals		$545	$478	$408

Exhibit E-3

PHILADELPHIA GAS WORKS
OTHER INTEREST
(Dollars in Thousands)

Line No.	Other Interest	Actual 2007-08	Estimate 2008-09	Budget 2009-10
1.	Tax-Exempt Commercial Paper	$3,993	$3,002	$2,618
2.	Variable Rate - 5th Series A-2	331	331	552
3	Variable Rate - 6th Series	834	679	-
4	LOC (Letter of Credit) Fees	-	847	8,413
5	Bond Discount, Issuance & Premium Expense	1,183	987	345
6.	Customer Deposits	471	555	552
7.	Miscellaneous Interest Expense	-	-	-
	Total Other Interest	$6,812	$6,401	$12,480
8.	Extraordinary Loss	$5,457	$5,202	$5,392
9.	AFUDC *	($338)	($399)	($865)
10.	* Total AFUDC	($338)	($399)	($865)

Exhibit F

PHILADELPHIA GAS WORKS
CAPITAL FUNDING & EXPENDITURES
(Dollars In Thousands)

Line No.		Actual 2007-08	Estimate 2008-09	Budget 2009-10
	SOURCES:			
1.	Capital Improvement Fund	$70,000	$45,000	$50,000
2.	Other Funding Sources	(8,258)	10,951	22,120
3.	**Total Sources**	$61,742	$55,951	$72,120
	USES:			
	Capital Expenditures:			
4.	Gas Processing	$2,515	$2,816	$4,992
5.	Distribution	47,748	40,208	51,684
6.	Field Services	5,813	5,633	4,654
7.	Information Technology	1,139	599	2,383
8.	Transportation	2,128	3,184	1,327
9.	Field Operations Initiative	-	-	
10.	Other Departments	2,399	3,511	7,080
11.	**Total Uses**	$61,742	$55,951	$72,120

Exhibit G-1

PHILADELPHIA GAS WORKS
REVENUE BOND DEBT SERVICE
(Dollars in Thousands)

Line No.	Year Issued	Series	Actual 2006-07	Estimate 2007-08	Budget 2008-09
Principal Payments					
1.	1999	16th	$ 8,945	$ 8,990	$ -
2.	2003	17th	9,710	8,650	7,550
3.	2004	18th	2,055	2,110	10,980
4.	1998	1st A	10,955	10,820	10,680
5.	1999	2nd	2,420	2,535	2,655
6.	2001	3rd	2,465	2,590	2,700
7.	2003	4th	2,075	2,540	2,670
8.	2,004	5th	-	-	2,480
9.	2003	6th	1,775	1,845	-
10.	2007	7th	-	3,045	3,170
11.	2009	8th Refund	-	-	2,500
12.	2010	9th New	-	-	1,255
	Total Principal Payments		$ 40,400	$ 43,125	$ 46,640

PHILADELPHIA GAS WORKS
OTHER LONG TERM DEBT SERVICE
(Dollars in Thousands)

Line No.	Year Issued	Series	Actual 2006-07	Estimate 2007-08	Budget 2008-09
	Principal Payments				
1.	1998	1st C Subordinate	$ 1,430	$ 1,500	$ 1,565
2.		Total Principal Payments	$ 1,430	$ 1,500	$ 1,565

Exhibit H-1

PHILADELPHIA GAS WORKS
WORKING CAPITAL DETAIL
(Dollars in Thousands)

Line No.		Actual Balance 8/31/08	Estimate Balance 8/31/09	Budget Balance 8/31/10
	ASSETS			
1.	Accounts Receivable	$231,595	$244,732	$238,705
2.	Accrued Gas Revenues	8,145	8,741	7,704
3.	Uncollectible Reserve	(140,435)	(137,820)	(134,977)
4.	Net Accounts Receivable	99,305	115,653	111,432
5.	Materials & Supplies	187,539	134,922	127,758
6.	Other Current Assets	5,626	13,306	14,486
7.	Total Assets	$292,470	$263,881	$253,676
	LIABILITIES			
	Accounts Payable:			
8.	Natural Gas	$41,300	$21,540	$19,833
9.	General	26,208	17,105	17,417
10.	Total Accounts Payable	67,508	38,645	37,250
11.	Other Current Liabilities	55,727	46,356	28,268
12.	Total Liabilities	$123,235	$85,001	$65,518
13.	Total Working Capital	$169,235	$178,880	$188,158
14.	Net Increase/(Decrease)	($8,968)	$9,645	$9,278

Exhibit H-2

PHILADELPHIA GAS WORKS
WORKING CAPITAL CHANGES
(Dollars in Thousands)

Line No.		Actual Change 8/31/08	Estimate Change 8/31/09	Budget Change 8/31/10
	ASSETS			
1.	Accounts Receivable	$2,821	$13,137	($6,027)
2.	Accrued Gas Revenues	(1,930)	596	(1,037)
3.	Uncollectible Reserve	9,796	2,615	2,843
4.	Net Accounts Receivable	10,687	16,348	($4,221)
5.	Materials & Supplies	39,769	(52,617)	($7,164)
6.	Other Current Assets	11	7,680	$1,180
7.	Total Assets	$50,467	($28,589)	($10,205)
	LIABILITIES			
	Accounts Payable:			
8.	Natural Gas	$9,475	($19,760)	($1,707)
9.	General	(2,582)	(9,103)	312
10.	Total Accounts Payable	6,893	(28,863)	($1,395)
11.	Other Current Liabilities	16,066	(9,371)	($18,088)
12.	Total Liabilities	$22,959	($38,234)	($19,483)
13.	Total Working Capital	$27,508	$9,645	$9,278

Exhibit H-3

PHILADELPHIA GAS WORKS
MATERIALS & SUPPLIES BALANCE @ 8/31

Non-Gas Inventory	Estimate 2008-09 Dollars	Budget 2009-10 Dollars
Storerooms:		
Belfield	$ 80,000	$ 79,000
Castor	60,000	59,000
Field Operations / Tioga	2,444,000	2,423,845
Meter Shop	571,000	564,900
Montgomery	927,000	917,900
Passyunk Mini	36,000	36,000
Passyunk Plant	1,061,000	1,050,005
Porter	74,000	73,000
Richmond Plant	2,297,000	2,284,350
Stationery	62,000	61,000
Transportation	388,000	384,000
Other Miscellaneous	12,000	12,000
Sub Total	$ 8,012,000	$ 7,945,000

Natural Gas Storages	Estimate 2008-09 Volume (Mcf)	Estimate 2008-09 Dollars	Estimate 2008-09 Avg. Price	Budget 2009-10 Volume (Mcf)	Budget 2009-10 Dollars	Budget 2009-10 Avg. Price
GSS - Transco	2,905,943	$ 21,805,896	$ 7.50	2,916,982	$ 19,660,725	$ 6.74
WSS	2,420,772	22,453,418	9.28	2,359,703	18,613,117	7.89
SS 1A	1,859,625	14,785,855	7.95	1,821,150	12,517,644	6.87
GSS - Tetco	2,743,796	17,559,271	6.40	2,772,140	17,384,057	6.27
Equitrans - Keystone	367,200	1,924,384	5.24	364,535	2,136,483	5.86
S-2	240,448	1,729,172	7.19	239,606	1,533,384	6.40
SS 1B	1,729,687	14,548,559	8.41	1,693,900	11,900,127	7.03
Eminence 1	300,575	2,775,736	9.23	294,728	1,973,289	6.70
Eminence 2	408,419	3,312,695	8.11	400,473	2,610,239	6.52
Sub Total	12,976,465	$100,894,986	$ 7.78	12,863,217	$ 88,329,065	$ 6.87
Richmond LNG	2,439,268	22,033,879	9.03	3,114,932	25,696,365	8.25
Passyunk LNG	134,699	1,287,439	9.56	204,779	1,849,699	9.03
Processing Costs	-	2,693,696		-	3,937,871	
Sub Total	2,573,967	26,015,014		3,319,711	31,483,935	
Total Gas Storage	15,550,432	$126,910,000	$ 8.16	16,182,928	$ 119,813,000	$ 7.40
Total Material & Supplies		$134,922,000			$ 127,758,000	

PHILADELPHIA GAS WORKS
DETAIL OF NON-CASH EXPENSES
(Dollars in Thousands)

Line No.		Actual 2007-08	Estimate 2008-09	Budget 2009-10
	DEPRECIATION			
1.	Depreciation on Historical	$42,868	$42,280	$43,409
2.	Less to Capital	(583)	(769)	(836)
		42,285	41,511	42,573
	SUBORDINATE PAYMENTS			
3.	Gas Commission	788	777	958
4.	City Payments	616	662	688
5.	Other Post Employment Benefits	25,834	25,558	24,615
6.	Swap Option Proceeds	(625)	(625)	(625)
		26,613	26,372	25,637
7.	Total Non-Cash Expenses	$68,898	$67,883	$68,210

	DETAIL OF DEPRECIATION & AMORTIZATION	Actual 2007-08	Estimate 2008-09	Budget 2009-10
8.	Depreciation Excluding Cost of Removal	40,021	39,280	40,409
9.	Discount, Premium & Issuance Expense	1,182	988	345
10.	Extraordinary Loss	5,457	5,202	5,392
11.	Total	$46,660	$45,470	$46,146

	NET CHANGE OTHER LONG TERM	Actual 2007-08	Estimate 2008-09	Budget 2009-10
12.	(Increase)/Decrease Other Assets	(11,851)	2,334	1,625
13.	Increase/(Decrease) Other Liabilities	35,853	24,417	18,204
14.	TECA Accretions	1,401	1,504	1,615
15.	Total	$25,403	$28,255	$21,444

PHILADELPHIA GAS WORKS
INSURANCE EXPENSE
(Dollars in Thousands)

Line No.	Insurance Type	Actual 2007-08	Estimate 2008-09	Budget 2009-10
1.	Property	$1,014	$1,070	$1,231
2.	Public Liability	1,802	1,865	2,832
3.	Workers' Compensation	372	370	407
4	Miscellaneous	40	45	50
5	Sub-Total	$3,228	$3,350	$4,520
6	Employees' Health	34,226	37,300	39,977
7	Employees' Group Life	1,586	2,000	1,900
8	Sub-Total	$35,812	$39,300	$41,877
9.	Total Insurance	$39,040	$42,650	$46,397

PHILADELPHIA GAS WORKS
PERSONNEL & PAYROLL DETAIL
(Dollars In Thousands)

DEPARTMENTS	Actual 2007-08 Average Personnel	Actual 2007-08 Payroll	Estimate 2008-09 Average Personnel	Estimate 2008-09 Payroll	Budget 2009-10 Average Personnel	Budget 2009-10 Payroll
ADMINISTRATION						
Officer's Salaries	-	$ 2,902	-	$ 2,675	-	$ 2,675
Incentive Bonus	-	-	-	-	-	-
President & Chief Executive Officer	2	67	2	67	2	67
Internal Auditing	2	178	2	178	2	178
Legal	14	904	14	889	14	911
Human Resources	15	820	17	949	17	949
VP Corporate Preparedness	5	201	5	202	5	204
Organizational Development	7	378	9	481	9	487
Policies & Compliance	4	281	4	282	4	284
Corporate Communications	6	389	6	347	6	312
Total	55	6,120	59	6,070	59	6,067
FINANCE						
Chief Financial Officer	-	-	-	-	-	-
Accounting & Reporting	18	915	17	908	17	944
SR VP Finance	7	384	8	497	8	497
Risk Management	7	409	7	409	7	412
Treasury	11	676	11	734	11	746
Total	43	2,384	43	2,548	43	2,599
CUSTOMER ACTIVITIES						
VP Customer Affairs	38	2,360	41	2,509	36	2,232
Collections	101	5,577	92	6,295	91	6,128
Bonus Awards	-	103	-	95	-	100
Commercial Resource Center	14	790	13	820	15	942
Account Management	35	1,851	34	2,012	34	2,087
Customer Review Unit	13	681	12	641	12	660
Customer Service	176	8,492	176	8,494	180	9,256
PMO	-	-	-	-	-	-
Total	377	19,854	368	20,866	368	21,405
MARKETING & PLANNING						
VP Marketing	2	51	2	51	2	51
Marketing	29	1,793	32	1,974	32	2,920
Strategic Planning	3	168	-	-	-	-
VP Regualtory & External Affairs	2	36	2	52	2	52
Gas Control & Acquisitions	22	1,493	24	1,568	24	1,535
Senior VP Business Transformation	8	566	9	637	9	597
Rates & Gas Planning	6	402	7	493	7	493
Total	72	4,509	76	4,775	76	5,648
OPERATIONS						
Chief Operating Officer	2	65	2	62	2	62
Senior VP Operations	1	-	2	33	2	44
VP Gas Management	2	42	2	42	2	42
Field Services	339	21,487	341	21,739	341	22,607
Distribution	464	28,056	472	29,627	467	30,254
Gas Processing	121	8,489	119	8,553	119	8,728
Operations Systems Support	4	251	4	263	4	263
Total	933	58,390	942	60,319	937	62,000
SYSTEMS & SERVICES						
Information Services	57	3,895	61	4,053	67	4,350
VP Technical Compliance	7	427	8	506	8	506
VP Supply Chain	4	194	4	195	4	195
Procurement	9	511	8	613	12	682
Engineering Services	9	571	9	620	9	622
Facilities Management	40	2,283	42	2,837	37	2,021
Telecommunications	3	1	3	210	3	210
Security	2	131	2	131	2	131
Materials Management	57	3,503	55	3,539	55	3,562
Chemical Services	4	254	4	283	4	261
Fleet Operations	39	2,565	38	2,520	38	2,565
Total	231	14,335	234	15,507	239	15,105
SUB-TOTAL	1,711	105,592	1,722	110,085	1,722	112,824
Labor Savings	-	-	(22)	(1,419)	(22)	(1,450)
SUB-TOTAL	1,711	105,592	1,700	108,666	1,700	111,374
Philadelphia Gas Commission	4	295	5	296	5	390
GRAND TOTAL PAYROLL	1,715	$ 105,887	1,705	$ 108,962	1,705	$ 111,764
Capitalized Full Time Equivalents	336	20,726	322	20,567	339	22,221

PHILADELPHIA GAS WORKS
REMAINING NORMALIZED EXPENSES

Line No.	Description	Department	Act/Est 2008-09	Budget 2009-10	Forecast 20010-11	Forecast 2011-12	Forecast 2012-13	Forecast 2013-14	Forecast 2014-15
1.	Base Rate Case	PUC	107,932	107,932	107,932	-	-	-	-
2.	Base Rate Case	PUC	39,231	39,231	39,231	-	-	-	-
3.	Management Audit	PUC	62,471	62,471	62,471	62,471	62,471	62,471	-
4.	Base Rate Case	PUC	-	48,000	48,000	48,000	48,000	-	-
5.	Workforce - Labor	Human Resources	-	29,000	29,000	29,000	29,000	-	-
6.	Workforce - Labor	Treasury	-	29,000	29,000	29,000	29,000	-	-
7.	Base Rate Case	PUC	-	-	122,000	122,000	122,000	122,000	-
8.	**Total**		**209,634**	**315,634**	**437,634**	**290,471**	**290,471**	**184,471**	**-**

PHILADELPHIA GAS WORKS
ENVIRONMENTAL EXPENSES

Environmental	Actual FY 2007	Actual FY 2008	Estimate FY 2009	Budget FY 2010	Forecast FY 2011	Forecast FY 2012	Forecast FY 2013	Forecast FY 2014	Forecast FY 2015	Forecast FY 2016		
Cost of Removal (Net)	$ -	$ -	$ -	$ 1,500,000	$ -	$ 500,000	$ -	$ -	$ -	$ -	$ 2,000,000	
Labor & Other												
Technical Support		-	187,806	268,877	277,290	334,793	292,079	300,123	306,125	7,653,125		
Other		-	-	-	-	-	-	-	-	-		
Total	-	-	187,806	268,877	277,290	334,793	292,079	300,123	306,125	7,653,125	9,620,218	
Purchased Service												
Purchased Service		-	853,000	465,000	2,029,750	150,750	73,750	73,750	73,750	1,531,250		
Assessment Study	-	-	-	-	-							
Total	-	-	853,000	465,000	2,029,750	150,750	73,750	73,750	73,750	1,531,250	5,251,000	
Maint. Contractors												
Misc. Contractors	-	-	11,500	117,500	1,765,000	1,237,500	245,000	145,000	145,000	3,505,000		
Total	-	-	11,500	117,500	1,765,000	1,237,500	245,000	145,000	145,000	3,505,000	7,171,500	
Total	-	-	1,052,306	851,377	4,072,040	1,723,043	610,829	518,873	524,875	12,689,375	22,042,718	
Cumulative	-	-	1,052,306	1,903,683	5,975,722	7,698,766	8,309,594	8,828,467	9,353,343	22,042,718	Total	$ 24,042,718
	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016		
Expense												
Labor	-	-	-	-	-	-	-	-	-	-		
Purchased Service	-	-	-	-	-	-	-	-	-	-		
Maint. Contractors	-	-	-	-	-	-	-	-	-	-		
Amortization	-	-	-	-	-	-	-	-	-	-		
Total	-	-	-	-	-	-	-	-	-	-		
Cumulative	-	-	-	-	-	-	-	-	-	-		
5 Year Amortization												
Cash	-	-	-	-	-	-	-	-	-	-		
Expense	-	-	-	-	-		-	-	-	-		
Deferred	-	-	-	-	-	-	-	-	-	-		
Cumulative L-T Deferred	-	-	-	-	-	-	-	-	-	-		
Less Current Amortized.	-	-	-	-	-	-	-	-	-	-		
Remaining L-T Deferred	-	-	-	-	-	-	-	-	-	-		
Deferred Costs	-	-	-	-	-	-	-	-	-	-		
Current Costs	-	-	1,052,306	851,377	4,072,040	1,723,043	610,829	518,873	524,875	12,689,375		
Cost of Removal	-	-	-	1,500,000	-	500,000	-	-	-	-		
Total	-	-	1,052,306	2,351,377	4,072,040	2,223,043	610,829	518,873	524,875	12,689,375		
Cumulative	-	-	1,052,306	3,403,683	7,475,722	9,698,766	10,309,594	10,828,467	11,353,343	24,042,718		
	08/31/2007	08/31/2008	08/31/2009	08/31/2010	08/31/2011	08/31/2012	08/31/2013	08/31/2014	08/31/2015	08/31/2016		
Environmental Expenses - IS	-	-	-	-	-	-	-	-	(271,585)	(12,689,375)	Environmental	$ (12,960,960)
Settlement Proceeds	2,936,666	1,100,000	131,750	-	-	-	-	-	-	-		
Expenses / Amortization	(1,091,478)	(652,179)	(1,052,306)	(851,377)	(4,072,040)	(1,723,043)	(610,829)	(518,873)	(253,290)	-	Expensed	$ (10,825,415)
Settlement Balance	8,502,187	8,950,008	8,029,452	7,178,075	3,106,035	1,382,992	772,163	253,290	0	0	Proceeds	10,825,415
											Total	$ 0
Total Liabilities	13,349,014	21,600,256	20,990,412	20,139,035	16,066,995	14,343,952	13,733,123	13,214,250	12,689,375	-		
Current Liabilities	(3,336,643)	(3,910,474)	(851,377)	(4,072,040)	(1,723,043)	(610,829)	(518,873)	(524,875)	(12,689,375)	(12,689,375)		
Non-current Liabilities	10,012,371	17,689,782	20,139,035	16,066,995	14,343,952	13,733,123	13,214,250	12,689,375	-	(12,689,375)		
Deferred Liability	4,846,827	12,650,248	12,960,960	12,960,960	12,960,960	12,960,960	12,960,960	12,960,960	12,689,375	-		

PHILADELPHIA GAS WORKS
ACCOUNTS RECEIVABLE & BAD DEBT EXPENSE

Accounts Receivable	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Beginning Receivable Balance	$ 228,774	$ 231,594	$ 244,732
Billed Gas Revenues	842,287	926,717	800,348
Proposed Rate Increase	-		-
Other Operating Revenues/Adjustments	31,137	33,533	30,116
Total Revenues	873,424	960,250	830,464
	95.48%	94.00%	95.00%
Collections Current Revenues	(833,960)	(902,635)	(788,941)
Adjustments	10,153	5,650	50
Net Write-Offs	(46,797)	(50,127)	(47,600)
Total Credit / Reductions	(870,604)	(947,112)	(836,491)
Ending Receivable Balance	231,594	244,732	238,705
Bad Debt Expense			
Current Year Net Receivable	231,594	244,732	238,705
Prior Period Adjustments	-	-	-
Adjusted Net Receivable	231,594	244,732	238,705
Reserve Factor	15.98%	19.25%	18.75%
Total Bad Debt Expense	37,000	47,111	44,757
Write Off Gas Accounts	(46,248)	(50,000)	(47,500)
Write Off Other	(549)	(127)	(100)
Reserve Balance			
Beginning Reserve Balance - Gas	149,207	139,959	137,070
Net Write-Off - Gas	(46,248)	(50,000)	(47,500)
Appropriation to Reserve - Gas	37,000	47,111	44,757
Ending Reserve Balance Gas	139,959	137,070	134,327
OAR Reserve	877	750	650
M & J Reserve	(401)	-	-
Total Reserve Balance	$ 140,435	$ 137,820	$ 134,977

PHILADELPHIA GAS WORKS
COLLECTIBILITY STUDY - May 2009

Classification		Balance Per Study Receivable	Collectible	Reserve % Uncollectible	$ Uncollectible
Defaulted Non-Budget Agreement					
	Commercial	-	-		
	Residential	3,525.73	3,458.70		
	Total	**3,525.73**	**3,458.70**	**1.90%**	**67.03**
Active Non-budget Agreement					
	Commercial	729,754.88	451,683.21	38.10%	278,071.67
	Residential	19,254,457.62	16,100,481.94	16.38%	3,153,975.68
	Total	**19,984,212.50**	**16,552,165.15**	**17.17%**	**3,432,047.35**
Off - Curb & Dig					
	Commercial	124,137.39	-	100.00%	124,137.39
	Residential	3,400,400.76	970,634.43	71.46%	2,429,766.33
	Total	**3,524,538.15**	**970,634.43**	**72.46%**	**2,553,903.72**
Finals					
	Commercial	9,352,264.04	1,259,244.51	86.54%	8,093,019.53
	Residential	49,327,517.88	8,391,797.43	82.99%	40,935,720.45
	Total	**58,679,781.92**	**9,651,041.94**	**83.55%**	**49,028,739.98**
Non-Budget Non-Agreement					
	Commercial	24,959,082.07	16,933,754.38	32.15%	8,025,327.69
	Residential	90,862,424.41	59,856,359.35	34.12%	31,006,065.06
	Total	**115,821,506.48**	**76,790,113.73**	**33.70%**	**39,031,392.75**
Not Classified		186,458.93	141,600.07	24.06%	44,858.86
	Total	**186,458.93**	**141,600.07**	**24.06%**	**44,858.86**
EMPP		**139.40**	**139.40**		
Active Budget Agreements					
Sub-Total Before CRP		**198,200,163.11**	**104,109,153.42**	**47.47%**	**94,091,009.69**
CRP AGREEMENTS					
CRP Current Program		10,946,150.54	6,097,710.53	44.29%	4,848,440.01
CRP Program *		829,570.07	416,256.00	49.82%	413,314.07
CRP Arrears		68,387,599.54	34,315,062.37	49.82%	34,072,537.17
CRP Regulatory Asset		-	-		-
Total CRP		**80,163,320.15**	**40,829,028.91**	**49.07%**	**39,334,291.24**
Inactive Accounts		**2,831,557.21**	**167,309.90**	**94.09%**	**2,664,247.31**
Credit Balances		**(13,626,603.90)**			
Grand Total *		**267,568,436.57**	**145,105,492.23**		**136,089,548.24**
Cycle 22, 23 GTS & Unfrozen Pay.		**2,865,287.24**			
Firm Transportation Charges					
Total AR		**270,433,723.81**			

*** CRP Program Includes CRP Liheap Make-Up (CRP-LL), CRP Relief Loan (CRP-RL), Non-Gas Charges Billed (CRP-LN) and Non-Gas Charges from Current year not billed (CRP-LD)**

NATURAL GAS
PRICE - VOLUME ANALYSIS

	Budget 2009-2010	Estimate 2008-2009	Budget 2010 Over(Under) Estimate 2009
N.G. Utilization (Mcf)	54,606,318	55,048,317	(441,999)
COMMODITY	$347,433,115	$472,184,139	($124,751,024)
Average Price	6.3625	8.5776	(2.2151)
DEMAND	$72,622,725	$74,797,384	($2,174,659)
Total Demand & Commodity	$420,055,840	$546,981,523	($126,925,683)
Average Price	7.6924	9.9364	(2.2439)
REFUNDS	-	(30,893)	30,893
TOTAL	$420,055,840	$546,950,630	($126,894,790)

CHANGE DUE TO:			
Commodity Price	($120,959,720)	(2.2151)	-25.82%
Volume	(3,791,304)	(441,999)	-0.80%
Demand	(2,174,659)		
Total Demand & Commodity	(126,925,683)	(2.2439)	-22.58%
Refunds	30,893		
TOTAL CHANGE	$ (126,894,790)		

PHILADELPHIA GAS WORKS
DETAIL OF OTHER OPERATING REVENUES
(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Finance Charges	$ 9,240	$ 10,166	$ 8,780
Returned Check Charges	201	221	191
Credit Card Charge Back Fees	7	8	7
Suspended Service Revenues	-	1	1
Customer Contract Obligation	144	157	135
Total	**$ 9,592**	**$ 10,553**	**$ 9,114**

Actual Weather 4,181 degree days (6.3%) Decline
TXCP $150.0 MM with $66.0 MM Outstanding @ 8/31/09
Collection Factor 94.0% & Additional $2.0M Pension Exp.
$18.0 MM City Payment Made and Granted Back to PGW
No Swap Payment 7/09

BUDGET OF CASH RECEIPTS AND DISBURSEMENTS
FISCAL YEAR ENDING AUGUST 31, 2009
(Millions of Dollars)

	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ACTUAL	ESTIMATE	ESTIMATE	ESTIMATE	
06/16/09	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	TOTAL
OPENING BALANCE - CASH INCLUDES $90.0 TXCP	49.3	9.1	54.0	44.7	27.3	36.9	53.4	100.0	115.4	8.1	46.4	31.4	49.3
RECEIPTS													
Gas	41.0	44.9	51.9	65.7	109.5	118.4	128.3	104.5	75.3	53.0	47.0	43.0	882.5
Other	2.1	0.7	0.4	0.7	0.3	0.3	1.4	0.7	0.8	0.3	0.5	0.9	9.2
Drawn from Capital Funds - Principal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.3	21.0	13.7	0.0	45.0
Drawn from Capital Funds - Interest	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Drawn from Lease Funds - Principal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Drawn from Lease Funds - Interest	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Advance (Repayment) of Capital Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pension Draw	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.3	18.3
City Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
City Fee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	18.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL RECEIPTS	43.1	45.6	52.7	66.4	109.8	118.7	129.7	105.2	86.4	92.3	61.2	62.2	973.4
TOTAL	92.4	54.7	106.7	111.1	137.1	155.6	183.1	205.2	201.8	100.4	107.6	93.7	1,022.7
DISBURSEMENTS													
Labor	10.8	11.3	11.6	12.6	13.0	11.8	11.3	12.0	10.8	12.7	13.3	12.5	143.7
Natural Gas	41.3	36.5	38.8	56.8	66.3	68.5	54.3	51.5	21.4	26.0	25.0	24.0	510.4
Debt Service	3.6	10.2	1.4	1.0	8.6	7.3	3.8	6.9	1.7	1.1	43.6	16.7	105.9
TXCP: Interest & Variable Rate Debt Fees	0.0	0.0	0.3	0.0	0.0	0.8	0.2	0.2	0.2	0.3	0.3	0.6	2.9
Repayment of City Loan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
City Fee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	18.0
Other Disbursements	10.6	17.7	9.9	13.4	12.3	13.8	13.5	19.2	11.6	15.9	14.0	15.2	167.1
TOTAL DISBURSEMENTS	66.3	75.7	62.0	83.8	100.2	102.2	83.1	89.8	45.7	74.0	96.2	69.0	948.0
MONTHLY CASH FLOW	(23.2)	(30.1)	(9.3)	(17.4)	9.6	16.5	46.6	15.4	40.7	18.3	(35.0)	(6.8)	25.4
CUMULATIVE CASH FLOW	(23.2)	(53.3)	(62.6)	(80.0)	(70.4)	(53.9)	(7.3)	8.1	48.8	67.1	32.1	25.4	
OPENING TXCP 90.0	90.0	73.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	0.0	20.0	40.0	90.0
TXCP ISSUED DURING MONTH	0.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	20.0	26.0	141.0
TXCP PAID DOWN DURING MONTH	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	148.0	0.0	0.0	0.0	165.0
ENDING TXCP	73.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	0.0	20.0	40.0	66.0	66.0
OPENING BALANCE - CASH	49.3	9.1	54.0	44.7	27.3	36.9	53.4	100.0	115.4	8.1	46.4	31.4	49.3
MONTHLY CASH FLOW	(23.2)	(30.1)	(9.3)	(17.4)	9.6	16.5	46.6	15.4	40.7	18.3	(35.0)	(6.8)	25.4
NET TXCP ACTIVITY MONTHLY	(17.0)	75.0	0.0	0.0	0.0	0.0	0.0	0.0	(148.0)	20.0	20.0	26.0	(24.0)
ENDING BALANCE - CASH	9.1	54.0	44.7	27.3	36.9	53.4	100.0	115.4	8.1	46.4	31.4	50.7	50.7
CITY LOAN AVAILABLE - END OF MONTH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CITY LOAN UTILIZED - END OF MONTH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CASH POSITION NET OF TXCP AND CITY LOAN	(63.9)	(94.0)	(103.3)	(120.7)	(111.1)	(94.6)	(48.0)	(32.6)	8.1	26.4	(8.6)	(15.3)	

Budgeted Weather 4,412 degree days
TXCP $150.0M with $29.0M Outstanding @ 8/31/10
Collection Factor 95.0%
$18.0M City Payment Made and Granted Back to PGW

BUDGET OF CASH RECEIPTS AND DISBURSEMENTS
FISCAL YEAR ENDING AUGUST 31, 2010
(Millions of Dollars)

		BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	BUDGET	
6/16/09		Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	TOTAL
OPENING BALANCE - CASH INCLUDES $66.0 TXCP		50.7	36.5	25.3	19.4	30.9	33.2	48.5	84.1	99.6	40.1	67.4	30.3	50.7
RECEIPTS														
Gas		38.8	45.0	47.4	66.0	81.6	95.9	107.8	89.6	74.1	55.8	45.4	42.5	789.9
Other		1.2	0.2	0.2	0.2	0.2	4.2	0.2	0.1	0.2	0.2	0.2	6.2	13.3
Drawn from Capital Funds - Principal		4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.5	4.5	4.5	4.5	50.0
Drawn from Capital Funds - Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Drawn from Lease Funds - Principal		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Drawn from Lease Funds - Interest		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Advance (Repayment) of Capital Fund		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pension Draw		1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.6	14.1
City Loan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
City Fee		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	18.0
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL RECEIPTS		45.1	50.3	52.7	71.3	86.9	105.2	113.1	94.9	80.0	79.7	51.3	54.8	885.3
TOTAL		95.7	86.8	78.0	90.7	117.8	138.4	161.6	179.0	179.6	119.8	118.7	85.2	936.0
DISBURSEMENTS														
Labor		12.8	13.6	12.8	14.0	13.3	12.6	13.0	13.1	12.7	13.1	13.7	12.9	157.6
Natural Gas		21.5	26.0	32.4	37.6	48.3	52.8	47.4	46.5	34.0	28.2	20.9	20.7	416.3
Debt Service		4.0	10.2	1.1	1.0	8.8	5.1	4.0	7.2	1.1	1.1	41.6	14.4	99.6
TXCP: Interest & Variable Rate Debt Fees		0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.1
Repayment of City Loan		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Swap Termination Payment		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
City Fee		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	18.0
Other Disbursements		20.8	11.6	12.1	7.1	14.1	19.3	13.0	12.5	11.7	12.0	12.1	9.6	155.9
TOTAL DISBURSEMENTS		59.2	61.5	58.5	59.8	84.6	89.9	77.5	79.4	59.5	72.4	88.3	57.7	848.5
MONTHLY CASH FLOW		(14.2)	(11.2)	(5.9)	11.5	2.3	15.3	35.5	15.5	20.5	7.3	(37.0)	(2.9)	36.8
CUMULATIVE CASH FLOW		(14.2)	(25.4)	(31.2)	(19.7)	(17.4)	(2.1)	33.4	48.9	69.4	76.7	39.7	36.8	
OPENING TXCP	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	(14.0)	6.0	6.0	66.0
TXCP ISSUED DURING MONTH		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	23.0	43.0
TXCP PAID DOWN DURING MONTH		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.0	0.0	0.0	0.0	80.0
ENDING TXCP		66.0	66.0	66.0	66.0	66.0	66.0	66.0	66.0	(14.0)	6.0	6.0	29.0	29.0
OPENING BALANCE - CASH		50.7	36.5	25.3	19.4	30.9	33.2	48.5	84.1	99.6	40.1	67.4	30.3	50.7
MONTHLY CASH FLOW		(14.2)	(11.2)	(5.9)	11.5	2.3	15.3	35.5	15.5	20.5	7.3	(37.0)	(2.9)	36.8
NET TXCP ACTIVITY MONTHLY		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(80.0)	20.0	0.0	23.0	(37.0)
ENDING BALANCE - CASH		36.5	25.3	19.4	30.9	33.2	48.5	84.1	99.6	40.1	67.4	30.3	50.5	50.5
CITY LOAN AVAILABLE - END OF MONTH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CITY LOAN UTILIZED - END OF MONTH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CASH POSITION NET OF TXCP AND CITY LOAN		(29.5)	(40.7)	(46.6)	(35.1)	(32.8)	(17.5)	18.1	33.6	54.1	61.4	24.3	21.5	

PREPARED DIRECT TESTIMONY
OF
JOSEPH R. BOGDONAVAGE
ON BEHALF OF
PHILADELPHIA GAS WORKS

Q. Please state your name and business address.

A. My name is Joseph R. Bogdonavage. My business address is 800 West Montgomery Avenue, Philadelphia, PA 19122.

Q. By whom are you employed and in what capacity?

A. I am employed by the Philadelphia Gas Works in the capacity of Senior Vice President - Finance.

Q. What are your principal responsibilities as Senior Vice President - Finance?

A. My principal responsibilities include the oversight and direction of PGW's Accounting & Reporting, Budget & Financial Forecasting, and Treasury, Departments. I am currently responsible for the overall preparation of PGW's Operating and Capital Budgets, review of Operating Budgets prepared by the individual departments, and the coordination, analysis, issuance and overall control of the complete annual Operating Budget filing. These activities include the preparation of analyses for the purpose of generating financial data to support the company's financial planning and decision-making processes. In addition, documentation is prepared regarding financial initiatives; i.e., proposed revenue bonds, commercial paper program offerings, base rate case presentations and the monthly financial statements. Finally, in coordination with the Controller and Director of Fiscal Oversight, the Budget area acts as a liaison between all departmental budget representatives regarding budgeting and financial forecasting procedures and variance analysis reporting.

Q. Have you previously presented testimony before the Philadelphia Gas Commission?

A. Yes, on numerous occasions. I have most recently presented testimony before this Commission on matters associated with PGW's 2008-2009 Operating Budget proceedings and Five Year Forecast. Prior to the above occasion, I presented testimony on PGW's proposed annual Operating & Capital Budgets and base rate increase requests.

Q. What are your responsibilities in connection with PGW's filing that is the subject of these hearings?

A. I am responsible for the overall development and preparation of the financial documentation, exhibits, and part of the supporting documentation included in PGW's proposed 2009-2010 Operating Budget filing.

Q. Please describe the factors that impacted the current 2008-2009 Estimate and also went into the development of the 2009-2010 Operating Budget and your involvement.

A. My direct involvement has been to facilitate the departmental interaction associated with PGW's Operating Budget process. This includes the review of all Operating Budgets prepared by the individual departments, updates to that information and the coordination, analysis, control and issuance of the complete 2009-2010 Operating Budget document. I have interacted with the City Finance Director and City Treasurer, PGW's Senior Team, and, in particular, Mr. Joseph F. Golden, Jr., PGW's Controller, in developing PGW's financial plan. PGW has developed a financial plan for the 2009-2010 Operating Budget which takes into account the Pennsylvania Public Utility Commission (PaPUC) approved December 2008 $60.0 million base rate increase which was precipitated by the ongoing uncertainty in the financial markets. In Fiscal Year 2010, PGW anticipates that it will continue the process to transform its business operations for the future benefit of its customers and the City of Philadelphia. Also, the Fiscal Year 2010 Operating Budget provides funding for certain corporate initiatives and expense increases, including resources to further analyze a real estate (Facilities) optimization plan, an increase in the funding for PGW's actuarial pension liability and employee health insurance coverage. In addition, PGW expects increased banking fees for providing liquidity support for its 8^{th} Series refunding bond issue and Commercial Paper Program. PGW continues its commitment to maintaining a safe and reliable distribution system, while keeping the enterprise in a position of financial stability and competitiveness. PGW along with many other municipal bond issuers experienced significant difficulties related to variable rate bond transactions. PGW was informed by the consortium of banks that provided liquidity support for the 6^{th} Series variable rate bonds that the current agreement would not be renewed in January 2009. In addition, that transaction had an interest rate swap that could have resulted in a substantial termination payment. The City of Philadelphia and PGW embarked on a plan to remarket or refund the existing 6^{th} Series variable rate bonds to minimize risk related to the interest rate swap and higher projected interest costs. The Fiscal Year 2010 Operating Budget includes projected interest costs and fees associated with a fixed rate and variable rate transaction. As of this date, the City and PGW are negotiating with four banks to provide letters of credit in support of a full variable rate transaction to refund the 6^{th} Series outstanding bonds. This transaction is expected to close at the end of July 2009. Once interest rates and costs are identified, PGW plans to revise its Fiscal Year 2010 Operating Budget to include the most up to date data. During the 2008-2009 Fiscal Period, PGW's bond rating with Moody's Investors Services, Standard and Poor's (S&P) and Fitch Ratings remained above investment grade with S&P and Fitch Ratings assigning a stable outlook, while Moody's assigned a negative outlook reflecting the ongoing economic downturn and collection and liquidity issues. The rating agencies continue to look for a strengthening of PGW's liquidity position instead of relying on external borrowings from its commercial paper program. PGW's c ommercial paper program which is currently at $150.0 million continues to be available to meet working capital requirements, while the capital construction fund is anticipated to have $68.0 million and $158.0 million in proceeds available at August 2009 and August 2010, respectively, to fund ongoing capital requirements. The current plan of finance anticipates the issuance of $150.0 million of revenues bonds to support the capital construction program. PGW's overall liquidity position is adequate to meet the projected working capital requirements for the upcoming winter period which currently reflects substantially lower prices for natural gas. The company continues to strive to maintain as high a collection rate as possible considering the state of the United States economy and its impact on customers' ability to pay during Fiscal Year 2009. Currently, the collection rate stands at approximately 93.1% through May 2009, with an expected August 2009 year end level of 94.0%.

The 2008-2009 heating season reflected an approximately 6.3% warmer than normal winter. The 2008-2009 Fiscal Period reflected declining natural gas prices compared to original projections, however customer accounts receivable balances are expected to be higher due to the anticipated reduction in the collection rate. The impact of higher customer accounts receivable balances on bad debt expense, additional operating and maintenance costs reflecting the concerted effort to decrease capital expenditures, higher pension expenses and delayed benefits associated with business transformation initiatives, accounted for the $9.7 million or 3.2% increase in overall operating and maintenance costs in the 2008-2009 Estimate compared to the 2008-2009 Budget Year as detailed on Exhibit A-1, Line 18. Some of the underlying assumptions that present a risk in the 2009-2010 Operating Budget are PGW's ability to sustain or improve upon its recent collection factor of 94.0% in the face of the current economic climate, and the timely attainment of the savings anticipated in the business transformation project. These factors combined with the approved base rate increase will impact PGW's goals of reducing short term debt, providing internal funds for capital and the longer term objective of reducing PGW's debt to equity ratio.

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

A. The purpose of my testimony is to provide the documentation and supporting methodology for the schedules and exhibits, provide detailed information regarding certain income and expense items, and, where necessary, explain the reasons for variations between the fiscal periods.

Q. Please describe the financial statements which support the 2009-2010 Operating Budget submission.

A. The Operating Budget for the 2009-2010 Fiscal Year has been summarized to indicate the functional expenses similar to previous Gas Commission presentations for comparative purposes. To facilitate an understanding and to illustrate the trend and level of operating expenditures by key functionality, data is provided on the Statement of Income, Exhibit A-1, of the Operating Budget presentation for the 2007-2008 Actual, the 2008-2009 Budget and Estimate and the proposed 2009-2010 Budget periods. The Cash Flow Statement, Exhibit A-2, reflects the sources and uses of cash and is one of the basic documents for financial planning at PGW. The

Revenue Bond Debt Service Coverage Statement is prepared in accordance with the Rate Covenant of the 1975 General Ordinance, as amended, and the 1998 General Ordinance, authorizing the issuance of revenue bonds. In compliance with the provisions of the Ordinances, PGW prepares and forwards a report to the Director of Finance of the City of Philadelphia within 120 days of the conclusion of each fiscal year detailing compliance with the revenue bond debt service requirements for such fiscal year. A calculation for the 2008-2009 and 2009-2010 Fiscal Periods is included with the Company's filing on Exhibit A-3.

Q. Who will explain the details of these documents?

A. I will present a financial summary of the impacts of the revenue and fuel cost data, which were filed and subsequently revised as part of the on-going Gas Cost Rate (GCR) filings with the PaPUC, and will continue through the Statement of Income to explain the impacts of financing and other financial considerations on the Cash Flow Statement and Revenue Bond Debt Service Coverage schedule.

Q. Would you proceed with your explanation of the Statement of Income.

A. The Statement of Income, presented as Exhibit A-1, includes projected operating revenues for Fiscal Year 2009-2010 of $839.1 billion.

Total Operating Revenues (Line 10) are forecasted to decrease by $101.0 million to $839.1 million a 10.7% decline when compared to the 2008-2009 Estimate of $940.1 million. The major portion of the reduced revenues reflects the significantly lower projected cost of natural gas, offset in part by the return to a normal heating season with the commensurate increase in sales to firm heating customers and the full year impact of the $60.0 million base rate increase. The 2009-2010 Budget Year represents 4,412 degree days, which is PGW's new 30 year average level, while the Estimate for the 2007-2008 Fiscal Period reflected 4,181 degree days, 283 degree days or approximately 6.3% less than the current normal level of 4,464 degree days. The 2009-2010 Budget Year assumes that firm heating sales are expected to be 1.7 Bcf greater than the 2008-2009 Estimate reflecting a return to a normal heating season. These factors will result in an increase in the projected margin to cover fixed costs. The projected 2009-2010 GCR of $7.29 per Mcf is substantially less than the average rate in effect for the 2008-2009 Fiscal Period, while revenues from gas transportation are anticipated to increase reflecting customers transferring from firm gas supply categories.

Non-Heating Revenues (Line 1) for the 2009-2010 Budget Year are projected at $50.2 million, a decrease of $16.4 million or 24.6%, compared to the $66.6 million expected during the 2008-2009 period. A reduction in sales to interruptible customers totaling .4 Bcf, and a $3.69 decline in the average price per Mcf is anticipated to result in an $8.1 million reduction in revenues. A decrease in firm non-heating billed revenues of $10.3 million is mainly due to the projected lower GCR in effect combined with the slightly lower sales. The GCR, the Universal Service Charge (USC), and the Interruptible Revenue Credit (IRC) for Fiscal Year 2008-2009 are anticipated to be over recovered by $22.0 million with $1.5 million applicable to non-heating revenues. The impact on firm non-heating revenues of the applicable charges for the Fiscal Periods 2007-2008 and 2008-2009 is anticipated to increase reported revenues by $2.0 million.

Gas Transportation Service Revenues (Line 2) are anticipated to rise by $4.7 million, or 18.6%, to $30.1 million from the prior year's level of $25.4 million due primarily to an additional .6 Bcf rise in the projected volumes of gas being transported for customers.

Heating Revenues (Line 3) during the 2009-2010 Budget Year are projected to total $742.1 million, $86.2 million, or 10.4% below the $828.2

million expected in the 2008-2009 period. The major factors for the $112.7 million decrease in billed revenues in the 2009-2010 Budget Year reflect a lower GCR in effect and a 1.7 Bcf increase in usage due to the return to a new 30 year average 4,412 degree day heating season. The GCR, USC and the IRC are expected to be over recovered by $22.0 million with $20.5 million applicable to heating revenues. The impact on firm heating revenues of the applicable charges for the Fiscal Periods 2007-2008 and 2008-2009 is anticipated to increase reported revenues by $26.5 million.

The **Weather Normalization Adjustment** (Line 4) is not expected to result in any substantial impact on heating customers during the 2008-2009 Fiscal Period. The 2009-2010 Budget Year anticipates a normal winter heating season which would not result in a WNA adjustment.

The **Unbilled Gas Adjustment** (Line 5) is anticipated to decline by $1.0 million to a total of $7.7 million due mainly to a lower average price per Mcf of gas used but not yet billed at August 2010. At August 2009, unbilled gas revenues of $8.7 million are expected to be $.6 million above the prior period level reflecting a higher average price per Mcf of gas used but not yet billed.

Q. What are the major components of Appliance Repair & Other Service Revenues?

A. The major components of Appliance Repair & Other Service Revenues are as follows:

Appliance Repair and Other Service Revenues (Line 7) totaling $8.7 million in the 2009-2010 Budget Year are associated with the parts and labor plan contracts for house heaters, automatic water heaters and other appliances. Also included in this category are reconnection charges generated by customer bill paid turn-ons. The projected revenues for the 2009-2010 Budget Year are expected to approximate the current years' level. The 2009-2010 Budget Year projects approximately 59,000 Parts & Labor Plans to be in force, the same level as the previous year.

The following schedule details appliance repair and other service revenues for the three fiscal years:

Appliance Repair and Other Service Revenues

(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Parts & Labor Plans	$6,826	$7,000	$7,000
Reconnection, Turn on Charges	1,781	1,745	1,708
TOTAL	**$8,607**	**$8,745**	**$8,708**

Other Operating Revenues (Line 8) principally reflects finance charges on delinquent customer account balances. The 2009-2010 Budget Year projects a decrease of $1.4 million to $9.1 million due to lower customer gas billings reflecting the projected declining fuel prices.

Q. Would you proceed with your explanation of the Statement of Income?

A. The Statement of Income includes projected **Total Operating Expenses** (Line 19) for the 2009-2010 Budget Year of $719.1 million, a $135.5 million or 15.9% decrease from the prior year. The major reasons for the variation in costs are explained below.

Natural Gas (Line 11) - Natural gas costs are forecasted to total $420.1 million in the 2009-2010 Budget Year, $126.9 million or 23.2% less than the $547.0 million level projected for the 2008-20098 Fiscal Period. The decrease from the 2008-2009 Estimate of natural gas costs primarily reflects lower commodity pipeline prices of $2.22 cents per Mcf totaling $120.9 million, while slightly lower supply requirements of .4 Bcf are expected to result in a $3.8 million decrease. Demand charges are forecasted to decline by $2.2 million. The 2008-2009 Fiscal Period reflected the receipt of natural gas refunds totaling $30,893. No natural gas refunds are projected to be received in the 2009-2010 Budget Year.

Contribution Margins (Line 14) - PGW forecasts that the margins to cover fixed overhead and other costs and interest expense are expected to total $419.1 million in the 2009-2010 Budget Year, a rise of $26.0 million from the $393.1 million level projected in the 2008-2009 Estimate. This margin represents the funds (total operating revenues less the cost of fuel) available to meet PGW's operational and financial requirements.

Labor and Fringe Benefits (Line 15) - This expense item, the second largest expense that PGW incurs, is budgeted to increase by $9.6 million or 6.4% to $159.4 million. The main factors that contribute to the added labor and benefits costs are as follows: (1) Operating labor costs in the 2009-2010 Budget Year are anticipated to increase by $1.1 million to $89.5 million from the current year level of $88.4 million. The 2009-2010 Budget Year reflects an average PGW personnel level of 1,700 employees. Currently, PGW has 1,706 employees as of May 2009. As shown on Exhibit A-1-1 (Line 32), PGW has projected labor cost reductions totaling $1.4 million in the 2009-2010 Fiscal Period. This decrease can be attributed, in part, to anticipated attrition in the workforce. During the 2008-2009 Fiscal Period the unionized workforce received a 3½% general wage increase effective May 15, 2009, the 2009-2010 Budget does not include funding for any future wage increases for unionized or non-union employees. PGW's collective bargaining agreement with unionized employees expires May 15, 2010. A rise in capitalized labor charges is anticipated for the 2009-2010 Budget Year lowering operating labor by $1.6 million, while overtime costs are projected to rise by $.8 million compared to the 2008-2009 estimated period. (2) Pension expenses are anticipated to rise significantly by $5.5 million to $21.1 million in the 2009-2010 Budget Year. (3) The $2.7 million rise in health insurance reflects premium increases for prescription drug and medical coverage for both active and retired employees. (4) Payroll taxes are expected to total $6.9 million in the 2009-2010 Budget Year, an increase of $.3 million from the prior year. The 2008-2009 estimated period reflects a $.2 million refund associated with prior period sales tax liability. A more detailed explanation of labor and fringe benefits (Exhibit C-3) will be provided later in my testimony.

Bad Debt Expense (Line 16) - PGW has provided separate supporting documentation for the Accounts Receivable and Bad Debt expense calculations (SD-5) and the most recent collectibility study as of May 2009 identifying the bad debt reserve requirement (SD-6). PGW anticipates a $44.8 million expense related to bad debt for the 2009-2010 Budget Year and $47.1 million for the current 2008-2009 Fiscal Period. The forecasted reduction in this expense reflects the lower customer billings associated with the decreasing fuel prices. PGW expects to attain a 94.0% collection rate for the 2008-2009 Fiscal Period, while a 95.0% collection rate target is reflected in the 2009-2010 Budget Year. PGW's focus on bill collection continues to remain at the forefront of all company activities as improvement in overall customer collections is paramount to improving cash flow and liquidity.

Other Expenses and Depreciation (Line 17) - The principal reasons for the $15.8 million decrease in these expense categories for the 2009-2010 Budget Year of $94.8 million resulted from reductions in the appropriation for losses, additional labor related charges to capital projects and projected benefits derived from business transformation initiatives. These decreases were partially offset by higher costs for advertising, general material, insurance, contracted maintenance, utilities, rentals, purchased services, postage, promotion, and depreciation expenses. A more detailed explanation of other expenses and depreciation (Exhibit C-4) will be presented later in my testimony.

Other Income (Line 21) - PGW expects a \$1.0 million increase in other income during the 2009-2010 Budget Year primarily as a result of earnings on restricted funds (bond proceeds and sinking fund deposits) reflecting an increase in investable balances and higher interest rates.

Interest Expense (Line 27) - Total interest expense of \$76.1 million in the 2009-2010 Budget Year represents an increase of \$2.5 million from the 2008-2009 Fiscal Period. Long-term debt (Line 23) interest costs are budgeted to decrease by \$3.3 million due mainly to the scheduled long-term debt maturities and reduced interest costs associated with PGW's interest rate swap agreement. Other interest (Line 24) expense is anticipated to rise by \$6.1 million in the 2009-2010 Budget Year primarily as a result of costs associated with providing bank liquidity support for the planned 8th Series refunding bond issue and with PGW's commercial paper program which is expected to be maintained at the \$150.0 million level in the 2009-2010 Fiscal Period. The Loss from the Extinguishment of Debt (Line 26) of \$5.4 million in the 2009-2010 Budget Year is expected to be \$.2 million higher than the prior period reflecting the continued expense amortization of prior bond refundings.

Net Earnings (Line 28) - The net earnings from Operations are forecasted at \$54.7 million for the 2009-2010 Budget Year. This reflects a \$33.0 million improvement from the 2008-2009 Fiscal Period projected earnings of \$21.7 million.

Q. Proceeding to Exhibit A-2, the Cash Flow Statement, would you please identify the individual items which account for the total sources of \$184.5 million for the 2009-2010 Budget Year shown on Line 11?

A. The Cash Flow Statement is one of PGW's primary financial planning and control documents. Through this format, the transition from an accrual accounting methodology applied in the Statement of Income is now presented on a cash basis. The principal sources of funds for PGW are net income, borrowings to support capital expenditures, and the commercial paper program.

Net Earnings (Line 1) totaling $54.7 million is a transfer from Line 28, Exhibit A-1, Statement of Income. It is the net result of PGW's operations after combining revenues and other income, less operating and interest expenses.

Depreciation and Amortization (Line 2) are sources of funds, as these items represent those (non-cash) costs chargeable to expense in the current period, although the actual cash payments were made primarily in prior periods. In the 2009-2010 Budget Year, this category is projected to rise by $.7 million to $46.1 million as a result of higher depreciation expense on utility plant.

Earnings on Restricted Funds (Line 3) represent cash withdrawals from restricted funds, principally the revenue bond sinking and capital improvement funds. In the 2008-2009 and 2009-2010 Fiscal Periods no cash withdrawals from these funds is expected. Earnings on these restricted accounts totaled $5.2 million and $5.8 million, in the 2008-2009 and 2009-2010 fiscal periods, respectively.

Increased/(Decreased) Other Assets/Liabilities (Line 5) reflects a change between the 2008-2009 and 2009-2010 Fiscal Years of $6.8 million. The main components that are reflected in this category are deferred operating expenses including environmental remediation, injury and damage reserves, interest accruals that continue to be made on the long term debt portion of Tax-Exempt Capital Appreciation (TECA) bonds.

Also, other post employment benefits that are now being reported are included in the liabilities.

The sum of net income and the previously mentioned adjustments is reported on (Exhibit A-2, Line 6) as available from operations and totals $116.5 million in the 2009-2010 Budget Year, $26.2 million greater than forecasted in the 2008-2009 Fiscal Year.

Funds Required for Capital (Line 7) represents one of the components of PGW's cash management process. The funds withdrawn from the capital improvement fund are utilized to fund PGW's capital expenditures. The 2008-2009 and 2009-2010 Fiscal Periods anticipate $45.0 million and $50.0 million, respectively, being withdrawn from the capital improvement fund to support capital spending.

Grant Income (Line 8) – The $18.0 million represents the grant back of the City payment to PGW to be used as project revenues available to cover debt service.

Temporary Financing (Line 10) - In the current 2008-2009 Fiscal Period, PGW's outstanding level of commercial paper notes is anticipated to be $66.0 million at August 31, 2009. During the 2008-2009 Fiscal Period, the full amount of commercial paper notes was repaid on May 15, 2009. PGW, for the remaining portion of the fiscal year, anticipates reissuing notes, as needed, to assist in meeting projected working capital requirements. The level of outstanding notes between August 2008 ($90.0 million) and August 2009 ($66.0 million) (Line 25) decreased by $24.0 million. The 2009-2010 Budget Year anticipates that commercial paper notes in varying levels will be outstanding to assist in meeting working capital requirements. The outstanding level of notes at August 2010 is forecasted to be $29.0 million. The overall impact of PGW's operations, including the approved $60.0 million base rate increase, improved customer collection levels, the forgiveness of the $18.0 million City payment, is projected to leave PGW with a cash balance of $50.6 million at August 2010, compared to the $50.7 million anticipated at the close of the 2008-2009 Fiscal Period.

The **Total Sources** (Line 11) of $184.5 million in the 2009-2010 Fiscal Year are expected to be $31.2 million higher than the level projected in Fiscal Year 2008-2009 mainly reflecting the additional net earnings from Operations.

Q. How are these Total Sources applied within PGW?

A. The Total Sources are utilized as detailed on the lower part of Exhibit A-2 under the category **Total Uses** (Line 21) of $184.5 million. The primary areas of expenditures are as follows:

Net Capital Expenditures (Line 12) represent expenses for approved capital budget projects. These costs totaling $72.1 million in the 2009-2010 Budget Year are projected to increase by $16.5 million from the 2008-2009 Fiscal Period level of $55.6 million. These expenditures include: (1) direct charges for labor, material, equipment, contractors and transportation services; (2) allocated expenses for fringe benefits and administrative and general expenses; and (3) an Allowance for Funds Used During Construction (AFUDC). The total costs are reported net of contributions, reimbursements and salvage.

Funded Debt Reduction (Lines 13 & 14) - This expense represents the payment of the principal portion of PGW's long-term debt under pre-determined debt amortization schedules. These payments include revenue bond debt service principal repayments. In the 2009-2010 Budget Year, these payments are expected to total $48.2 million, a rise of $3.6 million from the $44.6 million expected to be paid in the 2008-2009 Fiscal Period.

Temporary Financing Repayments (Line 15) - The 2008-2009 Fiscal Period anticipates that $24.0 million of outstanding commercial paper will be repaid leaving a balance of $66.0 million outstanding at August 2009, while the 2009-2010 Budget Year projects that an additional $37.0 million will be repaid by August 2010, resulting in an outstanding balance of $29.0 million.

Distribution of Earnings (Line 17) - This represents the annual $18.0 million payment made to the City of Philadelphia under the Philadelphia Facilities Management Corporation Agreement/Ordinance. This payment will be made to the City of Philadelphia and it will then be granted back to PGW to be utilized as project revenues.

Additions to (Reductions of) Non-Cash Working Capital (Line 18) - This category represents PGW's continuing effort to shift from the accrual method of accounting to a cash basis. The detail of working capital is presented on Exhibit H-1, and the annual changes in working capital, which specifically support Line 18 of Exhibit A-2 are detailed on Exhibit H-2.

Q. Would you please explain the major factors that resulted in the working capital requirements for the 2008-2009 Fiscal Year and the continuing impact on the proposed 2009-2010 Budget Year?

A. The $9.6 million net increase in working capital requirements during the 2008-2009 Fiscal Period (Exhibit H-2, Line 13) reflects changes in both assets and liabilities. The 2008-2009 Fiscal Period anticipates an increase in accounts receivable (Exhibit H-2, Line 1) of $13.1 million and a change in the reserve for bad debt (Exhibit H-2, Line 3) of $2.6 million resulting in a net gas accounts receivable increase of $15.7 million. Unbilled gas revenues (Exhibit H-1, Line 2) of $8.7 million at August 2009 are projected to increase by $.6 million. The increase in accounts receivable mainly reflects the projected decline in the collection of customer billings. PGW will be consulting with its external auditors to ascertain the required reserve for uncollectible accounts and has presented separate supporting documentation, which details the accounts receivable balance, reserve for uncollectible accounts and bad debt expense. Materials and Supplies (Exhibit H-2, Line 5) are anticipated to decrease by \$52.6 million principally due to a lower average price (\$2.39 per Mcf, or 22.7%) and volume of natural gas in storage inventories (1.5 Bcf), while Other Current Assets (Exhibit H-2, Line 6) is expected to increase by \$7.7 million due mainly to higher accrued capital related costs and reimbursable projects and increased prepaid insurance premiums for public liability and property coverage. Liabilities, namely accounts payables (Exhibit H-2, Line 10), are expected to decline by \$28.9 million principally due to reduced prices for natural gas purchases, and general trade payables. In addition, Other Current Liabilities (Exhibit H-2, Line 11) are expected to decrease by \$9.4 million mainly due to lower reserve requirements for the reserve for injuries and damages and a reduced level of customer deposits at year end. These decreases were partially offset by a net increase of \$7.5 million in the liability for the projected \$22.0 million over recovery of the 2008-2009 GCR, USC and IRC costs. The net impact of these working capital changes resulted in an increased working capital requirement for the 2008-2009 Fiscal Year.

The 2009-2010 Budget Year projects overall working capital requirements will raise by \$9.3 million (Exhibit H-2, Line 13). Net Accounts Receivable (Exhibit H-2, Line 4) are anticipated to decline by \$4.2 million mainly due to the projected lower GCR and its impact on lower customer receivable balances, while providing the necessary requirement for the reserve for bad debt and reduced accrued gas revenues as a result of the decreased price of natural gas. Materials and Supplies (Exhibit H-2, Line 5) are forecasted to decrease by \$7.2 million principally due to lower average prices for natural gas in storage of nearly 76.0 cents per Mcf or

9.3%. This decrease was offset, in part, by a .6 Bcf rise in the volume of natural gas in storage at August 2010. Other Current Assets (Exhibit H-2, Line 6) are expected to increase by $1.1 million reflecting slightly higher accrued capital related costs and reimbursable projects. Accounts Payable (Exhibit H-2, line 10) are expected to decline by $1.4 million reflecting lower year end natural gas purchase costs. Other Current Liabilities (Exhibit H-2, Line 11) are anticipated to decrease by $18.1 million reflecting the return to customers of the $22.0 million 2008-2009 over recovery of GCR, USC and IRC costs, offset by higher environmental remediation costs. These asset and liability changes result in an increased net working capital requirement of $9.3 million for the 2009-2010 Budget Year (Exhibit H-2, Line 13).

PGW's ending **Cash Balance** (Exhibit A-2, Line 24) at August 2009 is expected to total $50.7 million, $15.3 million less than the outstanding level of $66.0 million of commercial paper notes. This year end cash balance is $1.4 million greater than the $49.3 million actual cash balance in 2007-2008 which was $40.7 million below the $90.0 million level of outstanding short term borrowings. The 2009-2010 Budget Year projects a cash balance at year end of $50.5 million, which is anticipated to be $21.5 million greater than the outstanding level of $29.0 million of commercial paper notes. The ultimate goal for PGW in the future is to improve on its recent collection rate and partially support the financing of its capital programs with internally generated funds and minimize the use of short term borrowings.

Q. Could you explain the income and expense components that are utilized when computing the Revenue Bond Debt Service Coverage Ratio for the 2009-2010 Budget Year on Exhibit A-3?

A. The coverage ratio is calculated based on the 1975 Ordinance and the

1998 Ordinance which sets the priority of payments of outstanding long-term debt. In deriving data for the coverage calculation, several non-cash adjustments are made to both revenue and expense items:

Total Funds Provided (Line 7) - The funds provided in the proposed 2009-2010 Operating Budget total $862.9 million and are comprised of: (1) total gas and other operating revenues, (2) other income adjusted to include actual cash withdrawals from both the Capital Improvement and Revenue Bond Sinking Funds (rather than only the interest earned in the fiscal period), the $18.0 million in Grant Income, and (3) AFUDC on borrowed funds for capital expenditures.

Total Funds Applied (Line 12) - The funds applied reflect operating expenses from Exhibit A-1, Line 19, totaling $719.0 million, less certain non-cash and subordinate expenses (Line 11) totaling $68.2 million. The components of the non-cash expenses include: (1) depreciation expense included in operating expenses, (2) payments to the City of Philadelphia for miscellaneous services rendered, including Philadelphia Gas Commission expenses, and (3) other post employment benefits.

Funds Available to Cover Revenue Bond Debt (Line 13) are projected to be $212.1 million for the 2009-2010 Budget Year.

Revenue Bond Debt Service (Line 14) - The total funds applied to 1975 Revenue Bond Debt Service are $30.1 million, representing the scheduled cash payments of principal which are due annually with interest paid semi-annually.

Debt Service Coverage Ratio 1975 Revenue Bonds (Line 15) - The debt service coverage ratio for 1975 Ordinance Revenue Bonds is obtained by dividing Funds Available to cover 1975 Debt Service ($212.1 million) by Funds Applied to 1975 Debt Service Revenue Bonds ($30.1 million). The result produces a coverage ratio of 7.05 times. The mandatory coverage ratio for 1975 Senior Debt Service is 1.5 times. The remaining coverage ratios, as set forth in the 1998 Ordinance, are now calculated. Net available after 1975 Debt Service (Line 16) totaling $182.0 million is utilized to calculate the coverage ratio on 1998 Ordinance Senior Debt Service (Line 17) of $73.3 million at a mandatory 1.5 times. The projected calculation for this ratio is shown at 2.48 times (Line 18). The final component of the coverage calculation under the 1998 Ordinance is shown on (Lines 19 through 21). Net available after the 1998 Debt Service (Line 19) of $108.7 million is used to calculate coverage on 1998 Subordinate Debt Service (Line 20) of $2.0 million. The result is shown on (Line 21) as Debt Service Coverage Subordinate Bonds of 54.75 times. The mandatory requirement is 1.0 times on subordinate debt service. The projected coverage ratios for the current 2008-2009 Fiscal Period are expected to be 5.46 times on 1975 Ordinance debt service and 2.10 times on 1998 Ordinance debt service, while the coverage ratio on 1998 Subordinate debt service is expected to be 37.95 times.

Q. Returning to the Statement of Income (Exhibit A-1), could you explain in detail the items that are included under the category Labor and Fringe Benefits on Exhibit A-1, Line 15?

A. This category includes payroll costs (excluding that portion chargeable to capital activities), payments made to beneficiaries of PGW's employee pension plan and corresponding withdrawals from the pension fund. This category also includes the cost of premiums paid for employees' (both active and retired) health and group life insurance coverage, payroll taxes associated with FICA and Medicare and State unemployment taxes (exclusive of those taxes chargeable to capital activities) as detailed on Exhibit C-3.

Q. Are contractual labor escalations included in the periods covered on

Exhibit A-1?

A. Yes, a contract is in effect with the Gas Works Employees' Union for the period from May 16, 2007 to May 15, 2010. A 2½% general wage increase was effective for unionized employees on May 15, 2008. The remaining general wage increase of 3½% was effective May 15, 2009. The 2009-2010 Budget does not provide funding for any wage increase for unionized or non-union employees.

Q. Could you explain the difference in labor and fringe benefit expenses (Exhibit C-3) between the 2008-2009 and 2009-2010 Fiscal Periods?

A. The 2009-2010 Budget Year reflects payroll costs of $111.8 million, an increase of $2.8 million from the 2008-2009 Fiscal Year level of $109.0 million (Line 1). Operating labor costs (Line 3) are projected to rise by $1.1 million to $89.5 million, while labor charged to capital projects and other activities rose by $1.7 million.

The 2009-2010 Budget Year projects pension beneficiary payments (Line 4) to total $35.1 million, with a $14.0 million (Line 5) withdrawal from the pension fund to meet the anticipated payments. This will result in an actuarial pension expense of $21.1 million. The 2008-2009 Estimate for pension beneficiary payments is expected to be $33.8 million, with an $18.3 million withdrawal from the pension fund to meet the scheduled payments. The actuarial pension expense for PGW in the 2008-2009 Fiscal Year is forecasted to total $15.5 million. The actuarially computed pension expense for the 2008-2009 and 2009-2010 Fiscal Periods was based on updated information based on PGW's existing pension study prepared by its actuarial consultant. Health insurance costs (Exhibit C-3, Line 8) are anticipated to be $37.3 million in the 2008-2009 Fiscal Period, while the 2009-2010 Budget Year expects a $2.7 million increase to $40.0 million. PGW continues exploring ways to reduce costs for all employees' health coverage with its primary health care providers. Payroll taxes (Line 16) are anticipated to be $6.9 million in the 2009-2010 Budget Year an increase of $.3 million, the 2008-2009 estimate of $6.6 million included a prior period sales tax refund of $.2 million. The following schedule details the major components of the Labor and Fringe Benefits expense:

Labor and Fringe Benefits

(Dollars in Thousands)

	Actual 2007-08	**Estimate 2008-09**	**Budget 2009-10**
Operating Labor	$85,161	$88,395	$89,543
Pension Payments	32,839	33,866	35,128
Pension Fund Withdrawals	(18,581)	(18,335)	(14,065)
Group Life Insurance	1,586	2,000	1,900
Health Insurance	34,226	37,300	39,977
Sales Tax Refund	(904)	(214)	-
Payroll Taxes	6,581	6,823	6,955
TOTAL	**$140,908**	**$149,835**	**$159,438**

Q. Could you explain the personnel levels included on Exhibit C-3-1, and why PGW feels that the 2009-2010 Budget Year level is reasonable?

A. PGW, in the 2009-2010 Budget Year, expects to attain an average level of 1,700 employees. PGW currently has 1,706 employees and as of May 2009 had an average personnel level of 1,716. The company will most likely be slightly above its goal of 1,700 employees during the 2008-2009 Fiscal Period. PGW recognizes that certain areas of the company that provide critical functions need additional staffing and continued training; the 2009-2010 Budget provides the necessary resources. PGW is committed to adhering to the highest level of safety in the work place, while at the same time reducing overall workers' compensation claims through continued training.

Q. Please detail the items included in Other Expenses and Depreciation on Exhibit A-1, Line 17.

A. The expenses of $94.8 million for the 2009-2010 Budget Year include an appropriation for reserves and other losses (excluding the appropriation for uncollectible gas accounts), advertising, general material, property and liability insurance, contracted maintenance, utilities, rentals, purchased services, postage, promotion, depreciation and miscellaneous expenses.

Also included in this category are credits to operating expenses for labor-related fringe benefits such as insurance, taxes, pension expenses, and administrative and general costs chargeable to capital projects. In addition, non-utility revenues are also contained in this category. The detail of these expenses can be found on Exhibit C-4, Detail of Other Expenses.

Q. Have any adjustments been made to the expense categories detailed on Exhibit C-4 to reflect past Regulatory Commission orders?

A. Yes, PGW has complied with Regulatory Commissions' past orders which amortized certain non-recurring costs and normalized other expense items for ratemaking and budgeting purposes. The purchased services category mainly reflects these adjustments. Schedule (SD-4) provides documentation of the accounting for the remaining non-recurring expenses and projected costs associated with PGW's base rate increase and management audit.

Q. Please explain what is included in the Appropriation for Reserves and Other Losses on Exhibit C-4, Line 1?

A. This expense category includes appropriations to the Injuries and Damages Reserve for PGW's estimate of outstanding suits and claims and workers' compensation settlements, corporate loss settlements, and a provision for employees' compensated absences. As stated previously, this item excludes the appropriation for uncollectible accounts.

Q. What factors contributed to the increase in settlements during the 2008-2009 Estimate compared to the 2007-08 actual, and the higher projected level of settlements for the 2009-2010 Budget Year?

A. PGW's settlements for suits and claims and costs for workers' compensation were $2.7 million during the 2007-2008 actual period and combined with the appropriation of $4.8 million resulted in a year-end reserve balance of $7.5 million at August 2008. PGW's current projection of total reserves for outstanding suits and claims and workers' compensation settlements is expected to total nearly $3.1 million at August 2009, a decrease compared to the $6.1 million that was projected at August 2008. The 2008-2009 Fiscal Year primarily reflects the settlement of several suits and claims and long term workers' compensation claims. The appropriation to the Reserve for Injuries and Damages is expected to total $4.3 million during the 2008-2009 Fiscal Period resulting in an ending reserve balance of $5.8 million. Settlements for the 2008-2009 Fiscal Period are anticipated to total $5.9 million. The reserve balance at August 2009 is expected to provide coverage for suits and claims and workers' compensation settlements during the 2009-2010 Budget Year.

The 2009-2010 Budget Year projects settlements totaling $6.5 million, which includes costs associated with an outstanding class action suit during the upcoming period, while the appropriation of $3.5 million represents the required level necessary to provide a year-end reserve balance of $2.8 million. This forecasted reserve balance at August 2010 is expected to provide coverage for outstanding suits and claims and workers' compensation settlements anticipated during the 2010-2011 Fiscal Year.

PGW continues, through the Human Resources, Risk Management and Legal departments, and the use of a third party provider to handle its workers' compensation program, to identify all potential savings that can be achieved through an effective coordination of these activities.

The following schedule details the Injuries and Damages Reserve:

Injuries and Damages Reserve

(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Beginning Balance	$5,357	$7,456	$5,810
Settlements	(2,691)	(5,911)	(6,507)
Appropriation	4,790	4,265	3,460
Ending Balance	**$7,456***	**$5,810***	**$2,763***

*The required reserve balance represents the current portion of the total outstanding liability at the end of the fiscal period.

Q. Would you explain the items included in the Advertising expenses shown on Exhibit C-4, Line 2, and the increase of 70% comparing the 2009-2010 Budget Year to the 2008-2009 Estimate?

A. The major components of the advertising expenditures in the 2009-2010 Budget Year totaling $2.2 million are related to corporate campaigns to inform eligible customers of the availability of low income heating assistance programs, collection activities related to customer bill payment, PGW's Parts and Labor Repair Plans and customer appliance safety and corporate customer informational advertising. A major portion of the added spending reflects advertising costs in the 2009-2010 Fiscal Period related to a marketing campaign to promote natural gas as a clean air solution for potential customers. In addition, advertising is associated with Regulatory activities related to rate and tariff changes, meeting notices and hearings.

Q. What are the main components of the General Material costs included on Exhibit C-4, Line 3 for the 2009-2010 Budget Year and the 2008-2009 Fiscal Period?

A. In the 2009-2010 Budget Year, the three major operating departments are anticipated to utilize $5.3 million (net) of material in their operations (pipe, valves, appliance and replacement parts, etc.) approximately $.1 million or 2.5% greater than in the current period. The 19.4% overall increase in material mainly reflects a $1.0 million provision for material purchases associated with a possible work stoppage in May 2010. Without this cost overall material costs would be relatively unchanged at $5.1 million. PGW remains committed to an overall cost containment initiative to lower the overall departmental material utilization.

Q. What type of Insurance Premiums are included in the Insurance costs reported on Exhibit C-4, Line 4, and what is the reason for the $1.2 million or nearly 35% increase projected in the 2009-2010 Budget Year?

A. Insurance expense includes premiums for property, public liability, and workers' compensation coverage. Public liability coverage for the 2008-2009 and 2009-2010 Fiscal Years is expected to be maintained at the current $200.0 million level with a self-retention level of $1.0 million per occurrence. The renewal premiums for overall public liability insurance and workers' compensation coverage are anticipated to rise by nearly $1.0 million or 45% to $3.2 million in the 2009-2010 Budget Year up from the $2.2 million level experienced in the 2008-2009 Fiscal Period. The 2009-2010 Budget Year includes the impact of 1st party environmental and Cyber liability coverage that is expected to be in place. In the 2007-2008 through 2009-2010 Fiscal Years, the cost of providing insurance coverage is reflected as follows:

Insurance Expense

(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Property Insurance	$1,014	$1,070	$1,231
Public Liability & Workers' Comp.	2,174	2,235	3,239
Miscellaneous	40	45	50
TOTAL	**$3,228**	**$3,350**	**$4,520**

Other labor related insurance expenditures for employee health and group life insurance were previously referenced as a component of the labor and fringe benefit expenses.

Q. What expenses are included in Contracted Maintenance on Exhibit C-4, Line 5?

A. Contracted maintenance represents the cost of work performed by outside personnel, who are retained for their specialized experience in particular tasks. Software maintenance and/or licensing fees are also included in this category. This contracted work includes paving, painting, inspections and charges for maintenance of such items as gas engines, piping insulation, instrument repairs, tools, automobiles, elevators, air conditioning equipment, alarms, fire protection equipment, office and computer equipment and computer software maintenance, etc.

Q. Costs associated with Contracted Maintenance on Exhibit C-4, Line 5, are projected to rise by $.1 million or 2% in the 2009-2010 Budget Year. Please explain the reason for the increased expense.

A. The primary reasons for the additional contracted maintenance costs reflect planned maintenance activities on gas mains totaling $.1 million and higher maintenance software costs totaling $.1 million in Information services. PGW expects contracted maintenance expenses overall to total

$5.8 and $5.9 million in the 2008-2009 and 2009-2010 Fiscal Periods, respectively.

Q. What services are included within the category of Utilities on Exhibit C-4, Line 6?

A. Utilities include the cost of electric, telephone and water service. In the 2007-2008 through 2009-2010 Fiscal Years, the actual or projected costs for these services are:

Utility Expense

(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Electric	$2,120	$2,300	$2,341
Telephone	1,087	1,080	1,113
Water	482	391	391
TOTAL	**$3,689**	**$3,771**	**$3,845**

The 2% increase in utility expenditures projected for the 2009-2010 Budget Year mainly reflects higher costs for purchased electricity at PGW's facilities. The utility expenses included above exclude the cost of gas used by the company. This gas expense, in accordance with the prescribed FERC accounting methodology, is included in Natural Gas expense on Exhibit A-1, Line 11.

Q. What costs are included in Rental expenses, as presented on Exhibit C-4, Line 7?

A. Rental expenses include the rental and leasing of such items as computer related and telephone equipment, hand held microprocessors, transportation and construction equipment and PGW's customer service centers. This expense category in the 2009-2010 Budget Year is expected to remain relatively constant at $1.5 million.

Q. Please detail the type of expenses included within the category Purchased Services on Exhibit C-4, Line 8.

A. This expense category primarily includes professional and technical services such as: legal, engineering, auditing, consulting and computer related services, as well as, certain specialized services, e.g., advertising, production, collection agencies, armored car services, weather forecasting, banking and financial services and home weatherization services, etc., which are not normally available within the company's internal organization. The 2009-2010 Budget Year anticipates that purchased service costs will total $27.1 million, an increase of $4.5 million or nearly 20% above the 2008-2009 Estimate of $22.6 million. The major increases in the 2009-2010 Budget Year result from higher costs for a planned real estate optimization study, business process improvements, legal services, corporate training, technical information service support and janitorial and security services. The 2009-2010 Budget anticipates that weatherization and conservation expenditures will total $2.2 million, approximating the 2008-2009 Estimate. These costs are part of the non-fuel charges that are currently recoverable through the Universal Service Charge.

Q. Does the Postage Expense on Exhibit C-4, Line 9, include the cost of mailing all of the gas bills and notices being sent to customers?

A. Yes. PGW mails all of its monthly customer gas bills. In addition, this expense includes the cost for the mailing of collection notices, parts and labor plan contracts and general business correspondence. The 2009-2010 Budget Year total of $2.5 million is $.1 million greater than the $2.4 million expected to be incurred in the current fiscal period.

Q. Please describe the items included in the category Promotion on Exhibit C-4, Line 10.

A. The promotional expenses are associated with the Marketing department's initiatives to expand the use of natural gas in all market segments. The Marketing department included $.3 million for customer incentives in the 2009-2010 Budget Year for a burner tip conversion campaign.

Q. What are the components of Non-Utility Revenues presented on Exhibit C-4, Line 11?

A. The main component of these revenues is associated with the 1% commission paid by the Commonwealth of Pennsylvania for sales tax collection.

Q. On Exhibit C-4, Line 12, what expenses are charged to capital and what is the basis for the allocated charges to capital and corresponding credits to Operations?

A. Certain labor-related fringe benefit expenses, such as employee group life and health insurance, pensions and payroll taxes are charged initially to PGW's operating accounts on the Statement of Income, Exhibit A-1. In order to assign a proportional share of these costs to capital projects that utilize PGW personnel, a percentage of the total cost of the labor and fringe benefit expenses to the total direct payroll is calculated. On the basis of this calculation, these expenses are allocated to capital projects and operating expenses are reduced on the basis of the direct labor charges to capital. Also, administrative costs are allocated to capital based on the percentage of administrative and general expenses to total expenditures, excluding fuel costs. Capital projects are charged and operating expenses lowered on the basis of the total charges on a monthly basis to capital projects. The 2009-2010 Budget Year anticipates an allocation of $17.7 million in labor related fringe benefits and administrative and general costs to capital projects, a $.1.8 million increase compared to the 2008-2009 Fiscal Period, reflecting the additional capital spending forecasted.

Q. How are Depreciation rates determined and how do they relate to the expense listed in Exhibit C-4, Line 13?

A. PGW currently depreciates plant-in-service based on a 2004 depreciation study performed by the firm of Black & Veatch. The 2009-2010 Budget Year projects the utilization of a 2.4% composite depreciation rate and when applied to the projected plant-in-service balances accounts for the $43.4 million depreciation expense.

Q. Miscellaneous expenses included on Exhibit C-4, Line 15, are forecasted to decline by $22.1 million in the 2009-2010 Budget Year. Please explain the reasons for the reduced costs and the main components of this category?

A. Miscellaneous expenses are forecasted to total $12.9 million in the 2009-2010 Budget Year a decrease of $22.1 million primarily due to the $16.7 million net impact of anticipated benefits derived from Business Transformation initiatives, while a higher credit related to LNG inventory processing activities further contributed to the reduction. Also, a decrease of $.9 million in the reported expense for post employment benefits is expected in the 2009-2010 fiscal period. A detail of the components of the miscellaneous expense category is listed below:

Miscellaneous Expenses

(Dollars in Thousands)

	Actual 2007-08	Estimate 2008-09	Budget 2009-10
Expense of Employees	$678	$747	$1,116
Dues & Subscriptions	3,667	3,847	4,022
Taxes	21	21	30
PFMC Management Fee	381	359	360
Other Post Employment Benefits	25,834	25,558	24,615
Amortization Non-Recurring Expense	377	210	316
Deferred Compensation	361	337	344
Business Transformation Costs/(Benefits)	-	3,000	(16,700)
(Additions)/Reductions LNG Inventory	(901)	925	(1,245)
TOTAL	**$30,418**	**$35,004**	**$12,858**

Q. Does this conclude your testimony in this proceeding?

A. Yes, it does. Thank you.

RESOLUTION
AUTHORIZATION TO SUBMIT THE
PGW FISCAL YEAR 2010 OPERATING BUDGET TO THE
PHILADELPHIA GAS COMMISSION FOR REVIEW AND APPROVAL

I, ABBY L. POZEFSKY, Assistant Secretary of PHILADELPHIA FACILITIES MANAGEMENT CORPORATION, do hereby certify that the following is a true and correct copy of action taken by the Board of Directors of said corporation by unanimous consent to the adoption of this resolution dated September 17, 2008, pursuant to provisions of Section 5727(b) of the Non-Profit Corporation Law of the Commonwealth of Pennsylvania.

RESOLUTION
AUTHORIZATION TO SUBMIT THE
PGW FISCAL YEAR 2010 OPERATING BUDGET TO THE
PHILADELPHIA GAS COMMISSION FOR REVIEW AND APPROVAL

WHEREAS, pursuant to that certain Management Agreement by and between the Philadelphia Facilities Management Corporation ("PFMC") and the City of Philadelphia dated December 29, 1972, as amended, PFMC is the manager and operator of the Philadelphia Gas Works ("PGW");

WHEREAS, according to the Management Agreement §IV.2(a), PGW's Operating Budget is subject to the approval of the Philadelphia Gas Commission;

WHEREAS, according to the Management Agreement §IV.2(a), PGW's Operating Budget must be prepared with the aid of the Director of Finance and be consistent with the accounting methods described in the Management Agreement §IV.1, in a form and extent that is satisfactory to the Director of Finance and the Philadelphia Gas Commission;

WHEREAS, PGW has prepared its Fiscal Year 2010 Operating Budget and is currently developing the Forecast Fiscal Years 2011 through 2015 through the evaluation of the current needs and outlook of the municipally owned utility; and

WHEREAS, PFMC has conducted a review of PGW's Fiscal Year 2010 Operating Budget and finds it in satisfactory form and content, and will review the Forecast Fiscal Years 2011 through 2015 when they are fully developed;

NOW THEREFORE, BE IT

RESOLVED, that PFMC approves PGW's Fiscal Year 2010 Operating Budget, subject to further refinement by PGW management, should that become necessary or desirable; and that PGW is authorized to file with the Philadelphia Gas Commission for its approval and with the Director of Finance for his approval, as to form and content, the PGW Fiscal Year 2010 Operating Budget, in accordance with the Management Agreement §IV.2(a).

IN WITNESS WHEREOF, I have hereunto set my hand and have caused the corporate seal of said Corporation to be hereunto affixed this 1st day of June, 2009.

PHILADELPHIA FACILITIES
MANAGEMENT CORPORATION

Abby Pozefsky
Assistant Secretary

TAB

3

PGW St. No. 3

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

BARBARA C. BISGAIER

ON BEHALF OF

PHILADELPHIA GAS WORKS

DOCKET No. R-2009-2139884

December 2009

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. Barbara C. Bisgaier, Managing Director, Public Financial Management, Inc., 2 Logan Square, Suite 1600, Philadelphia, Pennsylvania 19103-2770, (215) 567-6100. I am a Financial Advisor to state and local governments and authorities.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Public Financial Management, Inc. I am a Managing Director and shareholder in the firm.

Q. SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I have been employed by PFM for more than 28 years. For approximately 26 of those years, I have had the title of managing director and have managed the firm's municipal utility practice. During my career at Public Financial Management, Inc., I have served as a Financial Advisor to a broad range of state and local governments and authorities. In particular, my experience has been concentrated in the area of publicly-owned utility systems. In addition to the Philadelphia Gas Works, my utility clients have included the Water Department of the City of Philadelphia, the Pittsburgh Water and Sewer Authority, the Harrisburg Water and Sewer Authority, the New Jersey Water Supply Authority, the North Jersey District Water Commissioners, the New Jersey Environmental Infrastructure Trust, the Passaic Valley Sewerage Commissioners, the Middlesex County (NJ) Utilities Authority, the Ocean County (NJ) Utilities Authority, the Atlantic County (NJ) Utilities Authority, the Southeast Morris County Water Authority, the District of Columbia Water & Sewer Authority and the Atlantic City Sewerage Authority.

In addition, I am currently the Financial Advisor to the City of Philadelphia and to the Commonwealth of Pennsylvania.

Over the course of my career, I have served as the advisor for the issuance of long-term debt having a par value in excess of $30 billion.

I have served as the Financial Advisor to the Philadelphia Gas Works since 1992. In that capacity, I have worked with the senior management of PGW and the City of Philadelphia on every debt financing completed by PGW during that time period, on the implementation and maintenance of PGW's tax-exempt commercial paper program, on each of PGW's rate cases before the PUC and with PGW in regard to its rating agency and credit provider (i.e. bond insurance and letters of credit) relations.

In the course of these various engagements, my responsibilities include general financial planning and the management of the debt issuance process. With regard to the financial planning aspect of my work, I assist clients with their development of capital financing strategies, debt policies, budgets and rate setting issues. With regard to the debt issuance process, I frequently serve as the liaison between my clients and the bond rating agencies, the municipal bond insurers and other credit-providing agencies. I also advise my clients throughout the debt issuance process as to the costs and benefits of various alternative approaches to business and financial issues under consideration. I am also frequently responsible for working with my clients to prepare disclosure documents, offering circulars and presentations to the bond rating agencies and credit enhancers.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have an A.B. degree from Mount Holyoke College and a Masters of City and Regional Planning degree from Rutgers University.

Q. HAVE YOU EVER TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes, I have testified before the Philadelphia Gas Commission and the Pennsylvania Public Utility Commission in PGW's Interim Rate Proceeding (R-00005654), and the associated base rate case and its Extraordinary Rate Proceeding (R-00017034F0002) and associated base rate case. I have also testified in PGW's 2006-07 base rate proceeding (R-00061931) and the 2008 request for emergency/extraordinary rates (R-2008-2073938).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is four-fold: 1) to provide an update to the PUC on the financial events that have transpired since the PUC granted PGW an extraordinary rate increase in December 2008 to assist PGW in weathering the storm of the national economic crisis and the attendant credit and liquidity contraction; 2) to describe the financial events PGW is facing in the next 12 months and the risks that still face the Company as it continues to try to persevere during the current recession; 3) to explain why it is crucial that the Commission needs, at a minimum, to maintain the current level of rates and take steps to insure that PGW's key financial indicators are stable or improving; and 4) to explain why it is prudent and necessary for the Commission to recognize the actions the Company is proposing to fund its existing liability related to other post employment benefits (other than pensions) ("OPEBs").

Q. PLEASE PROVIDE AN OVERVIEW OF THE KEY FINANCIAL TRANSACTIONS AND EVENTS THAT HAVE OCCURRED SINCE THE PUC'S EXTRAORDINARY RATE DECISION IN DECEMBER 2008.

A. The PUC granted extraordinary rate relief to PGW in December 2008 at what was, perhaps, the low point in the national financial crisis. The immediate crisis facing PGW had to do with its $313,390,000 Gas Works Revenue Bonds, Sixth Series (the "Sixth Series Bonds").

The Sixth Series Bonds were originally issued in January 2006 in the principal amount of $313,390,000 for the purpose of refinancing certain previously issued Gas

Works Revenue Bonds to achieve debt service savings. To achieve the lowest possible interest rate expense for PGW, the Sixth Series Bonds were issued as variable rate demand bonds in a weekly reset interest rate mode. The Sixth Series Bonds were insured by FSA with liquidity in the form of a Standby Bond Purchase Agreement provided by JPMorgan, the Bank of Nova Scotia and Wachovia Bank, N.A. Concurrently with the issuance of the Sixth Series Bonds, PGW executed a floating-to-fixed rate swap agreement with JPMorgan Chase Bank, N.A. (the "Swap"), a transaction that was common to many municipalities and public agencies because it was considered a prudent means of reducing the net interest cost of the bonds.

In August 2008, JPMorgan advised the City and PGW that they would not renew the Standby Bond Purchase Agreement upon its scheduled expiration on January 22, 2009. The consequence of this expiration, absent a replacement with a new liquidity facility, would be a mandatory tender of all Sixth Series Bonds on the expiration date and the conversion of the Sixth Series Bonds from a 30-year obligation to a five-year term loan. Pursuant to the terms of the Standby Bond Purchase Agreement, that term loan would be amortized over a five year period in ten semi-annual installments. The first payment (in the principal amount of $31,610,000 plus interest) would have been due on August 3, 2009.

At the January 22, 2009 expiration date of the Standby Bond Purchase Agreement, no substitute liquidity facility had been found and there was a mandatory tender of the Sixth Series Bonds; the obligation became the term loan described in the preceding paragraph.

In order to avoid the accelerated payments mandated by this term loan, the City and PGW determined that the best alternative was to refinance the Sixth Series Bonds on a variable rate basis. While the decision and best direction were clear, the actual execution of the refinancing was complicated by a number of factors. First among these was the fact that shortly after the City and PGW were notified that the Standby Bond Purchase Agreement would not be renewed, FSA, the bond insurer of the Sixth Series Bonds, was downgraded by each of the rating agencies. This meant that any refinancing to be done on a variable rate basis would require the replacement of both FSA and the liquidity provider; however, given the dismal state of municipal bond insurer credit ratings, this could only be done by the successful procurement of one or more direct pay letters of credit. The City began its search for direct pay letter of credit capacity for this purpose at precisely the same time that the implications of the world financial crisis were being evidenced by the collapse of Lehman Brothers and the lack of liquidity being experienced in the banking community. These external factors militated heavily against the possibility of finding letter of credit capacity for PGW.

An alternative means of refunding the Sixth Series Bonds was the issuance of fixed rate refunding bonds (i.e., bonds that would replace the variable rate bonds) since this approach would not have required the procurement of letter(s) of credit. But this alternative also presented a number of critical challenges, the most important of which were the uncertainty as to whether there would actually be a market for such a large issue of fixed-rate BBB rated bonds and the interest rates at which such bonds could be sold. This challenge was a function of the fact that the financial crisis had created a "flight to quality" and there was, through the first half of 2009, only a very small and very costly market for BBB-rated municipal bonds.

A further complication and expense presented by the fixed rate refunding alternative was the existence of the Swap. Were PGW to have executed a fixed rate refunding for 100% of the Sixth Series Bonds, it would have been necessary to terminate the entire Swap. The cost of terminating the entire Swap reached a high point of approximately $70,000,000 in November 2008. Had PGW been forced to do the entire refunding on a fixed rate basis, it would have also been necessary to increase the par amount of bonds outstanding by the amount of the Swap termination payment (to, in essence, finance the swap termination payment over time), whatever that amount ultimately was. This would have resulted in a bond issue of, at least, approximately $400,000,000.

In light of these various issues, the City and PGW concluded that they would follow a dual track that would consist of doing the largest possible variable rate refunding combined with the smallest possible fixed rate refunding. By keeping to a minimum the size of the fixed rate refunding, PGW would be able to minimize the cost of terminating the Swap and the potential difficulties and interest rate expense associated with the marketing of a large BBB rated offering. As further described below, the Company was successful in refunding the bonds with approximately 80% variable and 20% fixed rate bonds.

The ability to accomplish the goals of this dual track depended upon obtaining a letter of credit to cover the variable rate bonds as well as the willingness of FSA to continue to insure PGW's payments under the portion of the Swap that would remain in place despite the fact that it would no longer be insuring the Sixth Series Bonds.

Relatively early in the process, FSA agreed to remain as the Swap insurer, a major positive development.

With the passage of time, through two separate procurement processes and through a last minute decision by JP Morgan to participate in the transaction, the City was ultimately successful in finding four banks that were willing to provide direct pay letters of credit for the proposed refinancing transaction. They were Wachovia Bank, N.A. ($105,000,000), Scotia Capital ($50,000,000), Bank of America ($50,000,000) and JPMorganChase ($50,000,000). With this credit capacity, PGW was able to issue $313,285,000 Gas Works Revenue Refunding Bonds, Eighth Series (the "Eighth Series Bonds") in August 2009, the proceeds of which were used to refinance a total of $255,000,000 of the Sixth Series Bonds on a variable rate basis with the balance of $56,610,000 refunded on a fixed rate basis.

The portion of the Swap (in the notional amount of $54,765,000) associated with the Sixth Series Bonds that were refinanced on a fixed rate basis was terminated while the balance of the Swap (in the notional amount of $255,000,000) remained (and still remains) in place although it was restated so as to reflect the four series of variable rate bonds that were necessitated by the four separate credit facilities. The cost of the Swap termination was $3,791,000. PGW was able to achieve this lower-than-anticipated level of termination payment because only a portion of the Swap was terminated, because market conditions had improved since the November/December 2008 cost estimates had been made and because the refinancing was structured so that the fixed rate portion of the Eighth Series Bonds covered the earliest years of the loan and thus were associated with the lowest swap termination cost. The various parts of the transaction were priced on

August 12 and settled on August 20, 2009. Because of a three week extension granted by JPMorgan, the term loan amortization payment that had been due on August 3 was avoided.

The four direct pay letters of credit that now support $255,000,000 of Eighth Series Bonds will expire in August 2011; it will at that time be necessary to renew or replace them in order to maintain the Eighth Series Bonds in a variable rate mode and avoid an early swap termination payment.

Q. DID PGW EXPERIENCE ANY DIFFICULTIES MARKETING THE FIXED RATE BONDS?

A. The fixed rate portion of the Eighth Series Bonds was marketed on behalf of PGW by Goldman Sachs. Throughout the pre-sale process, PGW was warned continually by Goldman that there was only a very small market for BBB-rated bonds and that they anticipated the need for PGW to pay a significant interest rate premium to meet customer requirements. They also expressed concern about PGW's ability to sell the bonds at all. Ultimately, the difficultly in selling the fixed rate portion of the Eighth Series Bonds was most clearly manifested in the exceptionally high rates of interest demanded by the market (despite the fact that the fixed rate bonds were structured with a relatively short amortization schedule). PGW's difficulties in marketing the relatively small-sized ($54,765,000) fixed-rate Eighth Series Bonds were, unfortunately, fairly typical of what the entire municipal bond market has been experiencing since the middle of 2008, that is that the market has demonstrated little appetite for lower-rated bonds and is in the midst of a major "flight to quality". Recent financial events in all sectors of the market have created deep levels of concern about lower rate credits and, as a result, market participants will either avoid lower-rated credits all together or will demand significant interest rate penalties to pay them for taking this perceived risk. Another market dynamic that is also being felt most acutely by the issuers of lower-rated bonds is the fact that potential bond purchasers (who formerly would have relied upon bond insurance to mitigate risk and upon the rating agencies for accurate credit evaluation) are now being forced to examine more closely underlying credit risk themselves. The rating agencies, as a result of the fall-out from their ratings of pools of collateralized mortgage obligations, are experiencing a credibility crisis of their own. All of this market sensitivity to recent events has made the prospective bond purchaser that much more demanding of sound underlying financials that can be relied upon over an extended period of time.

Q. HOW IS PGW'S FINANCIAL PERFORMANCE COMPARED TO WHERE IT WAS PRIOR TO THE PUC'S EXTRAORDINARY RATE DECISION IN DECEMBER 2008.

A. The decision issued in the extraordinary rate case by the PUC in December 2008 was absolutely essential to each of the following elements of PGW's financial performance since December 2008:

1) As described above, PGW was able to refinance the Sixth Series Bonds. Without the extraordinary rate relief it is unlikely that this could have occurred as the rate decision was essential both to the maintenance of an investment-grade credit rating and to PGW's ability to obtain the four direct pay letters of credit that were essential to the transaction. Absent this outcome, PGW would have been faced with the financial catastrophe of a \$31.6 million term loan payment in August 2009 and a \$62 million term loan payment in each of calendar years 2010 through 2013.

2) PGW was able to sustain its access to the commercial paper market.

3) For the first time since the mid-90's, PGW actually ended its fiscal year 2009 with internally generated funds from operations, an indication of needed financial strength that will be crucial to support the Company when it attempts to market uninsured bonds this fall (as is discussed below).

4) PGW was able to pay down its outstanding commercial paper balances to zero (as it is required to do annually) without having to rely upon intra-fund borrowing from the capital account to achieve this end and was able to end fiscal year 2009 with no commercial paper outstanding.

In my view, it is not too strong a statement to say that the PUC $60 million rate grant saved the Company.

Q. DOES THIS MEAN THAT PGW IS NO LONGER FACING A FINANCIAL CRISIS?

A. No it does not. PGW faces a number of specific financial issues with which it must deal. These specific issues, which are detailed below, can only be satisfied if, at a minimum, PGW retains its investment grade credit rating and is able to demonstrate to a variety of investors and credit providers that it will continue to meet its financial obligations, will reduce its continued reliance on debt and will deal with the looming issue of its unfunded post-retirement benefits.

Q. WHAT FINANCIAL TRANSACTIONS IS PGW FACING AND WHICH CONTINUE TO BE AT RISK DUE TO THE CREDIT CRISIS?

A. In May 2010, PGW will face the first of its specific financial hurdles in that it will be necessary to renew the $150,000,000 letter of credit (provided jointly by JPMorgan, Scotia Capital and Wachovia) that supports the commercial paper program. Any deterioration in either PGW's financial outlook and/or a recurrence of the recent national liquidity crisis could be threatening to this requirement. While there is nothing that PGW can do to avoid another national liquidity crisis, the maintenance of PGW's improved financial picture that has resulted from the implementation of the extraordinary rate relief and other management actions will be critical to insuring that the banks in question remain willing to support the commercial paper program.

Further, in order to continue making capital improvements, including the essential main replacement program, PGW must continue to have market access for the sale of its bonds. The current plan calls for the sale of approximately $150 million of new money bonds in the fall of 2010. Because it is highly unlikely (if not impossible) that municipal bond insurance will be either available and/or cost-effective, PGW will be forced to sell its bonds based solely upon the strength of its own credit rating. It is my opinion, that the revocation of the extraordinary rate decision of December 2008 would seriously jeopardize not only the improving financial health of PGW but also PGW's investment grade credit rating. It will, at best, be extremely difficult and costly for PGW to sell $150 million of fixed rate bonds into a credit market that is deeply committed to the "flight to quality". Affirmation by the PUC of the extraordinary rate relief will put PGW in a position to access the credit markets although there can be no guarantee that the bond issue will be accomplished in a single attempt or without the need to pay a significant interest rate premium.

The four direct pay letters of credit that support the four variable rate series of Eighth Series Bonds discussed above are scheduled to mature in the summer of 2011. The best alternative from PGW's perspective will be to renew each of the letters of credit (hopefully, on a more cost-effective basis). A failure to renew or replace one or more of the letters of credit will place PGW back in the same position it was in when it was initially unable to renew the Standby Bond Purchase Agreement that supported the Sixth Series Bonds: *i.e.*, it would become necessary to convert some or all of the Eighth Series bonds to fixed rate bonds (if market access were available) and to terminate the portion or portions of the Swap associated with the converted bonds. The actual cost of such a conversion and Swap termination is unknowable at the current time, but it is an absolute certainty that PGW would be better served by being able to maintain the status quo with regard to the Eighth Series Bonds. That status quo depends upon the willingness of the four supporting banks (JPMorgan, Wachovia, Scotia Capital and Bank of America to continue providing credit support for the Eighth Series Bonds. Deterioration of PGW's financial picture and/or a loss of the investment grade credit rating could severely jeopardize the likelihood of these renewals. Worst case, a failure of these renewals and an inability to refinance some or all of the Eighth Series Bonds with fixed rate bonds would replicate the risk of the term loan scenario described above. Again, worst case, this would result in a $25.5 million term loan payment coming due during calendar 2012 with $51 million term loan payments then becoming due in 2013-16.

Finally, if the PUC were to fail to sustain all of the $60 million of extraordinary rate relief, PGW would, in my opinion, be forced to issue a Material Event Notice which is the legally-required formal notice to the market that a significant deterioration in an issuer's financial position has occurred. Such a notice would immediately alert the market to an impending financial crisis at PGW, In turn, this would put the commercial paper renewal in jeopardy, would certainly result in the rating agencies taking negative actions and would be a significant (or perhaps fatal) barrier to the sale of new money bonds in 2010. There would also, potentially, be a risk of increased rates on PGW's variable rate debt (the Fifth Series A-2 Bonds and the Eighth Series B, C, D and E Bonds).

Q. DO YOU BELIEVE THAT PGW MAY HAVE TROUBLE RENEWING ITS COMMERCIAL PAPER LETTER OF CREDIT?

A. At the current time, and in the expectation that the extraordinary rate relief will be sustained, I am cautiously optimistic that the commercial paper letter of credit will be renewed. Absent the maintenance of the extraordinary rate relief, however, I do believe there is a substantially increased risk that it will not be renewed. Even under the most favorable circumstances, there can be no doubt that the cost of the letter of credit will increase materially.

Q. IS THERE EVIDENCE THAT PGW MAY HAVE DIFFICULTY SELLING $150 MILLION OF NEW MONEY BONDS IN SEPTEMBER OR OCTOBER, 2010 (WITHOUT BOND INSURANCE)?

A. Yes. A major sea-change has occurred with respect to the prospects for marketing PGW's bonds, the full impact of which has yet to be determined. The recent financial crisis has created a so-called "flight to quality" meaning that prospective bond purchasers are evaluating each investment with a level of scrutiny that essentially has been absent from the municipal market for a number of years. With the fixed rate sale of a portion of the Eighth Series Bonds, PGW accessed the credit markets without the benefit of municipal bond insurance for the first time in more than 20 years. Before the essential collapse of the municipal bond insurance business, PGW had relied on bond insurance (however costly, but necessary) to insure that it was able to sell its bonds because it has always been difficult to find buyers for bonds that are just one step above investment grade. Absent the availability of bond insurance, PGW will have an extremely difficult time selling bonds in the planned amount (approximately $150,000,000) and with a normal (30 year) amortization schedule. At best, the market will accept such a transaction only if it is rewarded for doing so with a significant interest rate premium. The sale of the fixed rate portion of the Eighth Series Bonds was difficult and, despite the relatively smaller size of $58,285,000, proved a challenge that was reflected in substantially above-market interest rates. The market is currently seeking bonds in the A-rated and above category. Very few transactions in the BBB-range are being completed. At best, and that best assumes the maintenance of its existing credit ratings, PGW will have a difficult and ultimately costly time in selling its bonds in 2010.

Additionally, PGW has expressed an interest in issuing a new type of bonds that are available through the federal stimulus program. These so-called Build America Bonds ("BABs") are being used throughout the country to achieve material interest rate savings. For example, the State of Delaware recently sold $200 million BABs in a competitive process that produced $11 million of present value savings for them. PGW will have significant difficulty in taking advantage of this program because of its long-term credit rating. Although literally hundreds of BABs transactions have been completed since the program was authorized in the spring of 2009, to date only five of those transactions have been for issuers with credit ratings in the BBB category. If PGW is able to access this market, it is unlikely to experience anywhere near the level of benefit that is being achieved by higher-rated issuers like Delaware.

Q. WHAT IS THE OVERRIDING FACTOR THAT WILL AFFECT WHETHER PGW IS ABLE TO SELL ITS NEXT BOND ISSUE?

A. In my opinion, PGW needs to improve its financial results and be in a position to improve its bond rating. As noted above, the market is becoming more and more demanding of strong credit quality; PGW's access to the capital markets will increasingly depend upon its ability to demonstrate an improving rather than a static financial position. On the flip side, any deterioration in PGW's credit rating into junk bond status would be absolutely fatal to its ability to sell bonds to support the funding of the capital improvement program (and, in turn, continue to operate as a going concern).

Q. WHAT COULD CAUSE PGW'S CREDIT RATINGS TO DROP TO JUNK BOND STATUS?

A. A roll back of the extraordinary rate relief granted in December 2008, in whole or in part, would send a staggering message to the rating agencies and would, certainly with regard to Fitch and Standard & Poor's and perhaps Moody's as well, result in the loss of PGW's investment grade credit ratings because there would be no way for PGW to demonstrate that it could continue to meet its basic cash-flow and debt service coverage requirements. Such a loss would virtually guarantee that the 2010 renewal of the commercial paper letter of credit and the issuance of bonds at the end of 2010 would not be achieved. I believe this would occur despite PGW's maintaining, at least on an interim basis, the minimum fixed coverage rating that at least one rating agency (S&P) has indicated is required for PGW to maintain an investment grade credit rating.

Q. CAN YOU DISCUSS, IN PARTICULAR, WHY YOU CONTINUE TO BE WORRIED?

A. The market continues in a state of flux with unknowns at every turn. Any new external financial crisis (the failure of Dubai World or the crisis facing Greece's sovereign debt seem far afield of PGW, but so did the collapse of Lehman Brothers and the collateralized mortgage market a year ago) will seriously impact lesser-rated credits like PGW. PGW's limited liquidity, high debt burden and looming OPEB issue give it very limited flexibility in the face of market uncertainties. With three big hurdles (commercial paper renewal, the 2010 bond issue and the 2011 renewal of the letters of credit supporting the Eighth Series Bonds) on the immediate horizon, there is nothing that PGW can do to alter world financial affairs, but it must be given the chance to present the best possible picture to the financial markets so that it can take advantage of the limited financial strength that PGW currently enjoys.

Q. CAN YOU EXPLAIN THE QUANTITATIVE STANDARDS THAT S&P IS USING TO EVALUATE PGW AND THE RESULTS OF THAT ANALYSIS AS YOU UNDERSTAND IT?

A. Aside from the basic requirement that PGW meet all of its bond covenants (including 150% coverage of debt service of senior lien debt), S&P applies a standard that requires lower-rated credits to have annual revenues sufficient to cover all expenses, including debt service, in the range of 1.2 to 1.3 times. The lower the credit rating of the issuer, the more rigorously S&P applies the standard. Standard & Poor's believes that a failure to meet or exceed this standard means that any financial bump in the road will be fatal to a poorly rated credit that does not have much or any financial flexibility. Prior to fiscal year 2009, PGW had struggled (and in some years, failed) to meet this standard; the 2008 extraordinary rate relief put PGW above this threshold (at 1.27) for the first time in several years. A revocation of the extraordinary rate relief would certainly cause PGW to fall back to or below this threshold and would, once again, place the investment grade credit rating at risk. This is particularly true given S&P's often-expressed concern that market conditions, deteriorating collections as a result of the country's economic distress, or any unanticipated financial event would leave PGW unable to meet its obligations.

Q. HOW DOES S&P'S FIXED CHARGE COVERAGE CALCULATION TREAT THE PAYMENT OF THE $18 MILLION ANNUAL PAYMENT OBLIGATION THAT THE CITY IN RECENT YEARS HAS FORGIVEN?

A. S&P includes that payment in its calculation because it is still an obligation of PGW that it could be required to remit at any time. Indeed, given the City's present financial condition there is certainly the prospect that the City could retract its forgiveness.

Q. WHAT FINANCIAL INDICES CONTINUE TO CREATE RISK THAT PGW WILL BE DOWNGRADED OR WILL NOT BE ABLE TO SELL ITS BONDS WITHOUT BOND INSURANCE?

A. Aside from the specific market issues and rating maintenance concerns discussed above, there are a number of other financial issues that continue to threaten PGW's credit rating and hence its ability to sell bonds based, as must be, without municipal bond insurance on its own credit rating. These include its inordinately high debt to equity ratio, its lack of liquidity as measured by levels of cash and the growing focus of the marketplace on PGW's unfunded OPEB liability.

Q. CAN YOU EXPLAIN HOW UNFUNDED OPEB LIABILITY IS CAUSING RISK THAT PGW COULD BE DOWNGRADED OR NOT SELL ITS BONDS IN THE FALL?

A. It is my opinion that there will be increasing focus on this issue by the rating agencies, both positively and negatively, in the next several years. Several of the rating agency reports have already referenced PGW's accrued OPEB liability as a material risk factor in evaluating PGW's creditworthiness. For example, in its August, 2009 report S&P commented as follows:

> In our opinion, PGW has an above average debt burden. Debt represents about 86% of the utility's capitalization and average debt per customers about $2,800. The debt burden includes deferred funding of PGW's annual required contribution (ARC) to fund its other post employment benefits (OPEB). The ARC is about $25 million per year. We believe the continued deferral of the ARC will constrain PGW's future financial flexibility.... We believe PGW has a high debt burden. We expect debt levels to continue increasing in the short term because PGW does not generate excess margins and because the utility is not funding its ARC to amortize OPEB. PGW's OPEB liability totals $635 million. It expensed, but did not fund $26 million in OPEB liabilities in each of fiscals 2007, 2008 and 2009.

It is my opinion that a failure to deal with the issue will be viewed both as a financial threat to the well-being of an entity and as a failure of management and regulators to be proactive with regard to the issue. Conversely, an affirmative, implemented OPEB funding strategy will address both of those points and will be favorably viewed by the rating agencies. Large authorities around the country that may be considered PGW's peers are increasingly adopting various OPEB funding strategies. The more widely that this occurs elsewhere, the more it will become a rating agency standard to which PGW is held; a failure by PGW to deal with the OPEB issue will then become a material credit quality negative.

Moreover, PGW's OPEB funding proposal actually reduces the amount of debt in the capital structure by almost 200 basis points.(from almost 82% to 80%). PGW's historic over-reliance on debt financing combined with the magnitude of its unfunded OPEB liability continues to be the greatest sources of risk facing the Company, but if PGW's OPEB funding proposal is approved, PGW's Debt-to-Total Capitalization ratio will continue to improve over the five year planning period so that, by FY 2015 (on a pro forma basis) it is projected to reach 61% debt – 39% equity. This positive improvement over time will almost certainly be viewed as a very favorable development by the rating agencies and will enhance the chances that PGW could be upgraded from its present marginal level. At the very least, these projections will help to keep the Company from being downgraded if other events would create such a potential.

Q. WHAT COULD BE DONE TO PROTECT PGW'S CREDIT RATINGS IN ORDER TO ENHANCE ITS ABILITY TO SUSTAIN ITS COMMERCIAL PAPER PROGRAM, MAINTAIN OR IMPROVE ITS BOND RATING AND INCREASE THE LIKELIHOOD THAT IT WILL HAVE ACCESS TO THE LONG-TERM CREDIT MARKETS AT THE END OF 2010?

A. First and foremost, PGW must maintain the previously granted $60 million rate increase. Failure to do this would, in my opinion, precipitate a downgrade by each of the three agencies with all the problems attendant to that as I have described. The following items should not be viewed in order of priority, but rather each is critical to the financial well being of PGW and integral to any prospect of an improved credit rating. PGW must sustain its improved collection rate. PGW management must continue to demonstrate the efficacy of the Business Transformation Initiative. PGW must continue to improve its debt to total capitalization ratio by funding its OPEB liability and increasing earnings, continuing to produce some level of internally generated capital funding and reducing reliance on debt financing for capital expenditures. PGW must begin to implement a program that begins to fund its OPEB liability. PGW must have rates sufficient to generate an improved level of liquidity as measured by the maintenance of more robust cash balances.

Q. LOOKING AT PGW'S PRO FORMA FINANCIAL DATA AND ASSUMING THAT THE RATE INCREASE IT IS REQUESTING TO FUND ITS ACCRUED OPEB LIABILITY IS GRANTED ARE PGW'S FINANCIAL STATISTICS REASONABLE?

A. Just barely, but with the funding of OPEBs and a continuation of the positive results due to the extraordinary rate case, the company will be moving in the right direction.

Q. WHAT CRITERIA SHOULD BE USED TO JUDGE THE REASONABLENESS OF PGW'S CLAIMED RATE INCREASE?

A. PGW filed a petition for policy statement which set out a series of financial metrics that should be examined when determining whether PGW's revenue requirement is reasonable. They are as follows:

> In determining such just, reasonable and adequate rate levels for PGW, the Commission will consider PGW's test year and (as a check on test year results) projected future levels of non-borrowed year end cash, available short-term borrowing capacity, internal generation to fund Capital additions and debt-to-equity ratios. These measures will be considered (i) in comparison to the financial performance or requirements of comparable municipal or investor-owned utilities and (ii) from the standpoint of financial performance levels needed to maintain or improve PGW's bond rating thereby permitting PGW to access the capital markets at the lowest reasonable costs to customers over time.

Q. HOW DOES PGW'S FINANCIAL RESULTS AT PROPOSED RATES COMPARE UNDER THESE STANDARDS?

A. Based upon my experience these results continue to be very tenuous. For example:

Cash Flow and Liquidity: On a pro forma basis, assuming the first year funding of OPEBs, PGW is projecting that it will have 27.1 "days" of O&M expenses[1] and 104 days of liquidity. I have testified in the past that, in my experience, rating agencies expect municipal utilities to have cash working capital represented by at least <u>200</u> days of liquidity

Debt Service Coverage. On a pro forma basis, PGW will meet its minimum debt service coverage requirement on its 1998 Ordinance bonds, but only by 68 basis points. Similarly, PGW's S&P coverage results for the test year exceed the minimum required to produce an investment grade rating – but by very little: 1.4 times where the required range is 1.2 to 1.3 times.

Internally generated Funds for Construction. PGW anticipates that it will have $22 million in internally generated funds in FY 2010. FY 2009 was the first time PGW had any internal generation to fund construction since 1993. $22 million is still low. IGF should grow and it must continue in future years.

Debt –to-Total Capitalization. PGW's *pro forma* test year shows a Debt –to-Total Capitalization ratio of 80% debt, 20% equity. While this continues to be a major source of risk and concern for the rating agencies, PGW's OPEB funding proposal actually ameliorates the amount of debt in the capital structure by almost 200 basis points.(from almost 82% to 80%) Moreover, with OPEB funding, PGW's Debt –to-Total Capitalization ratio will continue to improve over the five year planning period so

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1 Total Operating and Maintenance expenses, less depreciation, divided by 365.

that, by FY 2015 (on a pro forma basis) PGW is projected to reach 61% debt – 39% equity. This positive improvement over time will almost certainly be viewed as a very favorable development by the rating agencies and will enhance the chances that PGW could be upgraded from its present marginal level. At the very least, these projections will help to keep the company from being downgraded if other events would create such a potential.

Q. CAN YOU DISCUSS HOW THESE RESULTS COMPARE TO COMPARABLE MUNICIPAL AND PRIVATE UTILITIES IN GREATER DETAIL?

A. Looking at data for comparable municipal and private utilities, PGW's results also fall short of the results for other such companies in many areas. This is explained in greater detail by Mr. Hanley.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

TAB

4

PGW St. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

SAMUEL M. KIKLA, FSA, MAAA

ON BEHALF OF
PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

DECEMBER 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Samuel M. Kikla. My business address is, One Commerce Square, 2005 Market Street, Suite 3510, Philadelphia, PA 19103.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Brown & Brown Consulting as a Consulting Actuary.

Q. WHAT ARE YOUR PRINCIPAL RESPONSIBILITIES WITH BROWN AND BROWN CONSULTING?

A. My principal responsibilities include management of the office's employee benefit and actuarial consulting practice and accounting for the practice's profit and loss. Additionally, I provide employee benefit and actuarial consulting services to clients.

Q. WHAT ARE YOUR PROFESSIONAL QUALIFICATIONS?

A. I am a Fellow of the Society of Actuaries, a Member of the Academy of Actuaries, and an Enrolled Actuary under ERISA. My Curriculum Vitae is attached as Exhibit SMK-1.

Q. WHAT IS YOUR RELATIONSHIP WITH PGW?

A. I have served as Brown and Brown's lead benefit consultant to PGW since 2001. Our responsibilities include PGW's medical, prescription drug, dental, and disability benefits provided to active and retired employees. We assist management in securing insurance coverage for these benefits, reviewing service providers on self-insured benefits and negotiating union benefits. Our firm has prepared the 2007 and 2009 actuarial valuation reports developing PGW's Retiree Welfare Plan obligations and expense under Government Accounting Standards Board ("GASB") 45.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to present to the Commission:

1. the impact of GASB 45 on PGW's annual operating expenses and balance sheet liabilities; and
2. the financial advantages to PGW and ratepayers of pre-funding the Retiree Welfare Plan obligations

Q. WHAT IS THE GOVERNMENT ACCOUNTING STANDARDS BOARD AND WHY IS IT APPLICABLE TO PGW?

A. In order for PGW to obtain an unqualified financial opinion from its auditors it must maintain its books of account in accordance with generally accepted accounting principles. The Government Accounting Standards Board ("GASB") is the source of generally accepted accounting principles for government entities. Accordingly, PGW follows GASB principles, as does the City of Philadelphia.

Q. WHAT IS GASB STATEMENT 45?

A. GASB Statement 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, is an accounting and financial reporting provision requiring government employers to measure and report the liabilities associated with other (than pension) postemployment benefits (or OPEB). Reported OPEBs may include post-retirement medical, prescription drug, dental, vision, life, long-term disability and long-term care benefits that are not associated with a pension plan. Government employers required to comply with GASB 45 include all states, towns, education boards, water districts, mosquito districts, public schools and all other government entities that offer OPEB and report under GASB.

Q. WHY WAS STATEMENT 45 ON OPEB ACCOUNTING BY GOVERNMENTS NECESSARY?

A. Statement 45 was issued to provide more complete, reliable, and decision-useful financial reporting regarding the costs and financial obligations that governments incur when they provide postemployment benefits other than pensions ("OPEB") as part of the compensation for services rendered by their employees. *Postemployment healthcare benefits,* the most common form of OPEB, are a very significant financial commitment for many governments.

Q. WHEN DID PGW HAVE TO COMPLY WITH GASB 45?

A. Implementation of Statement 45 was required for PGW's financial statements for the first fiscal year beginning after December 15, 2006. Since PGW is associated with the City of Philadelphia, PGW elected to comply when the City began to comply, beginning with the fiscal year September 1, 2006 through August 31, 2007.

Q. WHAT DOES STATEMENT 45 REQUIRE?

A. When PGW implemented Statement 45, it had to report, for the first time, annual OPEB cost and the unfunded actuarial accrued liabilities for past service costs. Statement 45 methodology requires PGW to:

- Accrue the estimated cost of OPEB benefits each year *during the years that employees are providing services* to PGW and its customers in exchange for those benefits.

- Provide, to the diverse users of PGW's financial reports, more accurate information about the *total cost of the services* that PGW provides to its customers.

- Clarify whether the amount PGW has paid or contributed for OPEB during the report year has covered its annual OPEB cost. Generally, the more of its annual OPEB cost that PGW defers, the higher will be: (a) its unfunded actuarial accrued liability; and (b) the cash flow demands on PGW and its rate payers in future years.

- Provide better information to report users about PGW's *unfunded actuarial accrued liabilities* (the difference between PGW's total obligation for OPEB and any assets it has set aside for financing the benefits) and changes in the *funded status of the benefits* over time.

Q. HOW WAS OPEB ACCOUNTING AND FINANCIAL REPORTING DONE PRIOR TO STATEMENT 45?

A. Prior to Statement 45, PGW followed a "pay-as-you-go" accounting approach in which the cost of benefits is not reported until after employees retire. This approach fails to account for costs and obligations incurred as PGW receives employee services each year for which PGW has promised future benefit payments in exchange.

Q. DOES GASB 45 REQUIRE PGW TO FUND THE OPEB OBLIGATIONS?

A. Statement 45 establishes standards for *accounting and financial reporting.* How a government actually finances benefits is a policy decision made by the government's officials. The objective of Statement 45 is to more accurately reflect the financial effects of OPEB transactions, including the amounts paid or contributed by the government, whatever those amounts may be.

Q. WHAT OPEB BENEFITS DOES PGW PROVIDE TO RETIREES?

A. PGW provides medical insurance, prescription drug benefits, life insurance, and dental insurance to retirees and their dependents. A summary of these benefits is contained in Appendix 3 of our September 1, 2009 valuation attached as Exhibit SMK-2.

Q. HAVE YOU PREPARED AN ACTUARIAL VALUATION OF PGW'S OPEB OBLIGATIONS AND ANNUAL EXPENSE IN ACCORDANCE WITH GASB 45

A. Yes. We prepared valuations at September 1, 2007 and September 1, 2009. As indicated, a copy of our September 1, 2009 valuation is attached as Exhibit SMK-2.

Q. HOW IS PGW'S ANNUAL OPEB EXPENSE DETERMINED?

A. From an accrual accounting standpoint (the basis of accounting required for all transactions in PGW's financial statements), the reported annual expense relates entirely to transactions (exchanges of employee services for the promised future benefits) that *already have occurred.* Statement 45 requires PGW to report costs and obligations incurred as a consequence of receiving employee services, for which benefits are owed in exchange. The *normal cost* component of annual expense is the portion of the present value of estimated total benefits that is attributed to services received in the current year. The annual expense also includes an amortization component representing a portion of the unfunded actuarial accrued liability ("UAAL"), which relates to past service costs. PGW's unfunded actuarial accrued liability as of August 31, 2010 is $653,753,000. PGW is amortizing UAAL over a 30 year open period. The OPEB cost for the fiscal years ending August 31, 2009 and August 31, 2010 is $46,009,000 and $48,975,000 respectively. The components of PGW's annual OPEB Cost for fiscal years 2007 through 2010 is shown in Exhibit SMK-3, with a projection through fiscal year 2016.

Q. DID PGW HAVE TO BOOK A FINANCIAL-STATEMENT LIABILITY FOR THE ENTIRE UNFUNDED ACTUARIAL ACCRUED LIABILITY?

A. Statement 45 does not require immediate recognition of the UAAL as a financial-statement liability. The requirements regarding the reporting of an OPEB liability on the face of the financial statements work as follows:

- Governments may apply Statement 45 prospectively. At the beginning of the year of implementation, PGW started with zero financial-statement liability.

- From that point forward, PGW accumulates a liability called the *net OPEB obligation,* if and to the extent its actual OPEB contributions are less than its annual OPEB cost or expense.

- The net OPEB obligation (not the same as the UAAL) will increase rapidly over time if, for example, PGW's OPEB financing policy is pay-as-you-go, and the amounts paid for current premiums are much less than the annual OPEB cost.

- Since PGW's financing policy is pay-as-you-go, at August 31, 2009 PGW has accrued a net OPEB obligation of $78,207,000. The net OPEB obligation is expected to grow to $105,112,000 at August 31, 2010 if PGW continues on a pay-as-you-go funding basis (Exhibit SMK-3).

Q. HOW SIGNIFICANT IS THE DISCOUNT RATE IN DETERMING PGW'S ACCRUED OPEB OBLIGATIONS?

A. Paragraph 13 of the GASB 45 standard describes the discount rate selection (italics added).

"The investment return assumption (discount rate) should be the estimated long term investment yield on the investments that are expected to be used to finance the payment of benefits. ... For this purpose, the investments expected to be used to finance the payment of benefits are (1) plan assets for plans which the employer's funding policy is to contribute an amount at least equal to the ARC, (2) assets of the employer for plans that have no plan assets or (3) a combination of the two for plans that are being partially funded. The discount rate for a partially funded plan should be a blended rate that reflects the proportionate amounts of plan and employer assets that are expected to be used."

At the present time, the discount rate selected by management is 5% and is based on a continuation of PGW's policy to fund OPEB obligations on a pay-as-you-go basis. If PGW receives a rate increase which begins at $42,500,000 (and decreases thereafter) for the five year period commencing September 1, 2010, it can begin to fund the OPEB liability and revise its funding policy to establish a Trust and commence funding the OPEB liabilities. By contributing the Annual Required Contribution determined under the GASB methodology, a discount rate equivalent to the long term earnings rate on pension trust assets can be used. Currently this rate is 8.25% for PGW's pension plan. Using 8.25% for the discount rate decreases the unfunded actuarial liability to $455,491,000 as of September 1, 2010 (on a present value basis) and reduces the fiscal year 2010-11 Annual Required Contribution from $50,179,000 to $45,853,000.

Further, funding will improve PGW's balance sheet and debt to equity ratio to transfer the net OPEB obligation of $105,112,000 as of August 31, 2010 to the Trust. This can be accomplished by contributing an additional $21,022,000 in excess of the Annual Required Contribution over a five year period. (Exhibit SMK-5)

Q. WHAT ARE THE ADVANTAGES OF FUNDING VERSES PAY-AS-YOU-GO?

A. Financially, funding the OPEB obligations allows the plan to earn higher investment returns since the funds are not held internally in general PGW assets. This enables PGW to use a higher discount rate for determining plan liabilities, producing a significantly lower actuarial accrued liability ($198,262,000 decrease) and lower annual expense ($4,326,000 decrease). Future funding requirements (rate actions) will be lower due to the higher investment returns on the invested assets. Essentially this means that, by funding now, ratepayers will have to pay some $200 million less (on a present value basis).

Further, public entities that fund their GASB plans often see a favorable reflection in their bond ratings due to a perception of increased solvency and reduced risk. Additionally, funding the plan provides an asset to employees and the commitment to funding can have a positive effect on employee morale.

Q. HOW DOES FUNDING THE OPEB OBLIGATIONS CHANGE PGW'S FINANCIALS GOING FORWARD?

A. Exhibit SMK-4 shows our projection of the financial effects of revising PGW's funding policy to contribute at least the annual required contribution commencing with the 2010-11 fiscal year. Exhibit SMK-5 shows our projection of the financial effects of contributing $21,022,000 in excess of the annual required contribution for five years in order to transfer the net OPEB obligation to the Trust.

Q. HOW DOES FUNDING THE OPEB OBLIGATIONS AFFECT PGW'S RATE INCREASE?

A. PGW's rate increase for OPEBs is made up of 3 elements:

1. PGW's annualized cost for OPEB using the higher discount rate (8.25%) is expected to average $ 46,823,000 over the five fiscal years ending 2010 through 2014 under accrual accounting, which is higher than its $26,187,000 average "pay-as-you-go" cost by $20,636,000 during this period.

2. PGW's transition cost at August 31, 2010 is expected to be $455,491,000. It is proposed that this cost be amortized over a 30 year closed period beginning September 1, 2010. The average amortization cost, including interest, rolled into each year's annualized OPEB accrual cost over the five year period is $41,300,000.

The total for items 1 and 2 for the test year is $21.5 million

3. PGW's deferred OPEB cost accrued as of August 31, 2010 is expected to be $105,112,000. It is proposed that these costs be amortized over a 5 year period, which would result in 1/5 of the total ($21,022,000) in its base rate claim.

PGW's total OPEB actuarial accrued liability as of August 31, 2010 was $653,753,000 (unfunded). PGW's actuarial accrued liability would be reduced to $455,491,000 if PGW adopted a policy of funding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

RESUME OF SAMUEL M. KIKLA, F.S.A., M.A.A.A.

Mr. Kikla has over forty years of experience in the employee benefits arena. A graduate of Colgate University, he is a Fellow of the Society of Actuaries, a Member of the American Academy of Actuaries, and an Enrolled Actuary with ERISA.

Experience

Mr. Kikla's expertise spans the Employee Benefits, Individual Life, and Casualty Insurance fields, including:

- Consultant on Employee Benefit Plan design, funding, and Administration including Pension, Group Life, Health and Disability;
- Actuarial valuations of Retirement plans; calculations of liabilities and expense under FAS 87 and 88, GASB 25 and 27.
- Analysis of cost and funding implications of alternative Pension, Profit Sharing and 401(k) Plan designs;
- Actuarial analysis and design of Retiree Medical Plans; Development of FAS 106 and GASB 45 obligations and expense;
- Feasibility studies, analysis of experience and development of reserves and premiums for insured and self-insured Group Life, Health and Disability Plans; pricing options under cafeteria and flexible benefit plans;
- Consultant on ERISA and Internal Revenue Code compliance for Employee Benefit Plans;
- Actuarial studies to determine the financial impact of Federal Occupational Disease (Black Lung), and Social Security legislation; and Development of Workers' Compensation rate filing for Black Lung Insurance rates in Pennsylvania;
- Executive Director and Actuary of a large self insured Joint Health Insurance Fund.
- Analysis of Medicare Part D Prescription options for employers with retiree medical benefits; attestation of actuarial equivalence.
- Actuarial Consultant and Appointed Actuary to Insurance companies on Workers' Compensation, Medical Malpractice, rates and reserves;
- Development of business plans for establishing captive insurance companies in the U.S., Bermuda and other offshore domiciles.

Mr. Kikla has testified as an expert witness before the PA State Insurance Department on rate filings, at union arbitration hearings related to employee welfare benefits, as well as on pension liabilities litigation in various courts.

Education

Mr. Kikla graduated from Colgate University with a Bachelor of Arts degree in mathematics.

Employment History

- 1996 – Present — Consulting Actuary
  Brown & Brown Consulting, Philadelphia, PA
- 1979 – 1996 — Vice President & Actuary
  National Director of Employee Benefit Actuarial and Consulting Services
  Sedgwick James Consulting Group, Philadelphia, PA
- 1978 – 1979 — Manager
  Touche Ross & Co., Minneapolis, MN
- 1974 – 1978 — Consulting Actuary and Manager of Actuarial Services
  Johnson & Higgins of Pennsylvania, Inc., Pittsburgh, PA
- 1972 – 1974 — Consulting Actuary
  William M. Mercer Company, Pittsburgh, PA
- 1968 – 1972 — Actuarial Assistant, Group Department
  Massachusetts Mutual Life Insurance Co., Springfield, MA

Professional Affiliations

- Fellow of the Society of Actuaries
- Enrolled Actuary under ERISA
- Member of the American Academy of Actuaries
- Pennsylvania and Minnesota Life and Health Insurance Brokerage license
- NASD Series 6 license.

Mr. Kikla has served on the pension committee of the American Academy of Actuaries from 1989 to 1991 and was Chairman of the Pension Committee Chairman for 1992 and 1993.

Publications

- "Accounting for Retirees"; Public Risk
- "How to make the Best Use of Your Actuary"; Pension World
- "Mergers and Acquisitions: How They Impact Pension Plans"; Pension Management

Exhibit SMK-2

PHILADELPHIA GAS WORKS

PHILADELPHIA GAS WORKS RETIREE WELFARE PLAN
SEPTEMBER 1, 2009 ACTUARIAL VALUATION

Prepared by:
Brown & Brown Consulting
Philadelphia, PA 19103

September 2009

ACTUARIAL STATEMENT

We present in this report the results of the actuarial valuation of the Philadelphia Gas Works Retiree Welfare Plan for the fiscal year beginning September 1, 2009. This report presents our determination of PGW's September 1, 2009 obligations and accrual expense under Government Accounting Standards Board Statement 45 (GASB 45). Use of the valuation report for purposes other than fulfilling the requirements of GASB 45 may not be appropriate.

The actuarial calculations and accounting figures shown in this report are based upon the census data submitted by the plan sponsor, and the plan provisions and actuarial assumptions summarized in the Appendices. We have not performed a comprehensive audit of the data provided, but have reviewed the data for reasonableness.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices. The calculations reported herein are consistent with our understanding of the provisions of GASB 45. The actuarial assumptions employed in the development of the postretirement welfare cost have been selected by Brown & Brown Consulting with the concurrence of the plan sponsor. In our opinion, these assumptions are individually reasonable on their own merits and consistent in the aggregate.

The consulting actuaries are members of the American Academy of Actuaries and meet the Qualification Standard of the American Academy of Actuaries to render the actuarial opinion contained in this report.

Samuel M. Kikla, FSA, MAAA	William J. Patti, MAAA
Enrolled Actuary Number: 08-01290	Enrolled Actuary Number: 08-06221

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EXECUTIVE SUMMARY

This report presents Philadelphia Gas Works (PGW) management with information concerning the health and welfare benefits provided to employees after termination or retirement. PGW provides eligible retirees with medical, prescription drug, dental coverage, and life insurance coverage.

We performed an actuarial valuation as of September 1, 2009 of the cost and liabilities attributable to these postemployment welfare benefits using the methods and procedures under GASB 45 Statement for Accounting and Financial Reporting by Employers for Postemployment Benefits Other than Pensions.

The following are the highlights of our report:

- The Actuarial Accrued Liability at:

	September 1, 2009	September 1, 2007
Retirees	$345,765,000	$343,453,000
Active employees	$290,027,000	$230,251,000
Total	$635,792,000	$573,734,000

- The projected cash cost for retiree medical benefits for the fiscal year beginning September 1, 2009 is $23,752,000. By 2018, this amount is projected to be approximately $41,749,000.

- The Annual Required Contribution (ARC) for the fiscal year beginning September 1, 2009 under the GASB accounting standard is $50,152,000 assuming a 30-year open period amortization of the Unfunded Actuarial Accrued Liability. The Annual OPEB Cost is $48,975,000.

SUMMARY OF VALUATION RESULTS
(In thousands)

	Medical and Dental	Prescription	Life	Total
Actuarial Accrued Liability				
Retiree	$ 164,649	$ 167,612	$ 13,504	$ 345,765
Active	$ 176,420	$ 110,195	$ 3,412	$ 290,027
Total	$ 341,069	$ 277,807	$ 16,916	$ 635,792
Assets	$ -	$ -	$ -	$ -
Unfunded Actuarial Accrued Liability	$ 341,069	$ 277,807	$ 16,916	$ 635,792
Normal Cost	$ 4,935	$ 3,343	$ 96	$ 8,374
Discount Rate				5.00%
Healthcare Trend	9% grading down to 4.5% over 6 years (post-65) 13% grading down to 4.5% over 10 years (pre-65)			

ANNUAL REQUIRED CONTRIBUTION AND OPEB COST
(in thousands)

	Fiscal Year Ending 8/31/2010	Fiscal Year Ending 8/31/2009
(1) Normal Cost with interest	$ 8,793	$ 8,311
(2) Amortization of Unfunded Actuarial Accrued Liability (30 year open period)	$ 41,359	38,484
(3) Annual Required Contribution (ARC)	$ 50,152	$ 46,795
(4) Net OPEB Obligation at beginning of year	$ 78,207	$ 52,255
(5) Interest on Net OPEB Obligation	$ 3,910	$ 2,613
(6) Adjustment to the ARC	$ (5,087)	$ (3,399)
(7) Annual OPEB Cost (AOC)	$ 48,975	$ 46,009

Annual OPEB COST Summary

Fiscal Year Ending	Annual OPEB Cost ($ thousands)	Percentage of Annual OPEB Cost Contributed	Net OPEB Obligation ($ thousands)
8/31/2007	$44,501	42.3%	$25,685
8/31/2008	44,850	40.8%	52,255
8/31/2009	46,009	43.6%	78,207

RETIREE WELFARE PLAN 10-YEAR EXPECTED CASH PAYOUT

Current Retirees

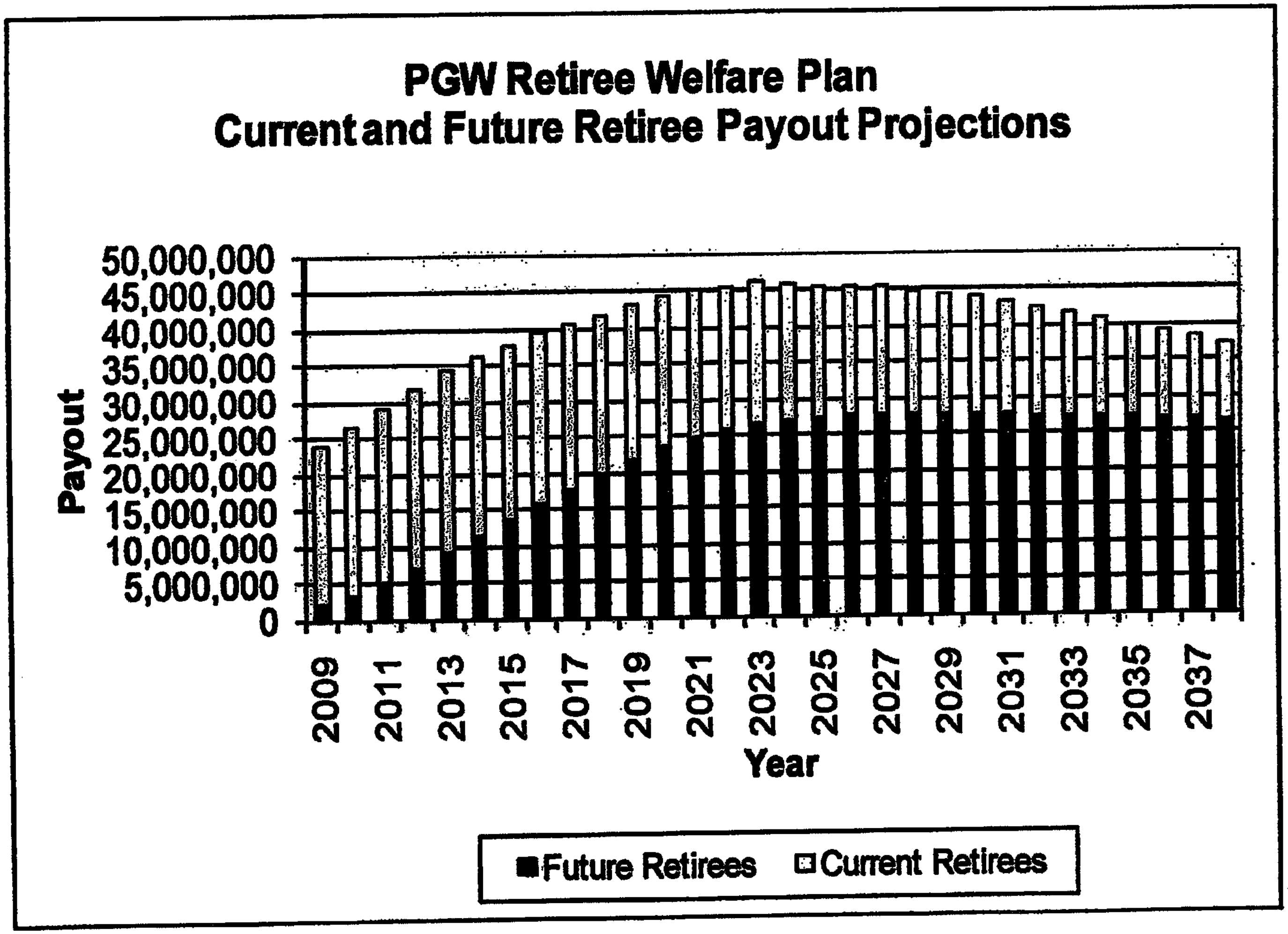
Year	Medical and Dental	Prescription Drug	Life	Total
2009	11,971,723	9,137,748	772,223	21,881,694
2010	12,638,328	9,698,392	792,612	23,129,332
2011	13,107,856	10,159,395	809,914	24,077,165
2012	13,332,560	10,531,078	824,722	24,688,360
2013	13,453,770	10,757,025	837,937	25,048,732
2014	13,107,232	10,865,483	846,610	24,819,325
2015	12,513,750	10,899,057	851,256	24,264,063
2016	11,928,355	10,912,633	852,445	23,693,433
2017	11,134,401	10,916,753	851,027	22,902,181
2018	10,403,028	10,868,898	847,349	22,119,275

Future Retirees

Year	Medical and Dental	Prescription Drug	Life	Total
2009	1,378,380	471,327	20,306	1,870,013
2010	2,506,641	784,848	29,777	3,321,266
2011	3,800,914	1,147,279	40,888	4,989,081
2012	5,321,716	1,594,728	54,540	6,970,984
2013	6,955,302	2,061,027	68,848	9,085,177
2014	8,654,299	2,567,518	84,540	11,306,357
2015	10,227,679	3,066,323	100,891	13,394,893
2016	11,883,508	3,619,690	119,285	15,622,483
2017	13,265,365	4,210,759	137,536	17,613,660
2018	14,611,746	4,859,733	158,482	19,629,961

Current and Future Retirees

Year	Medical and Dental	Prescription Drug	Life	Total
2009	13,350,103	9,609,075	792,529	23,751,707
2010	15,144,969	10,483,240	822,389	26,450,598
2011	16,908,770	11,306,674	850,802	29,066,246
2012	18,654,276	12,125,806	879,262	31,659,344
2013	20,409,072	12,818,052	906,785	34,133,909
2014	21,761,531	13,433,001	931,150	36,125,682
2015	22,741,429	13,965,380	952,147	37,658,956
2016	23,811,863	14,532,323	971,730	39,315,916
2017	24,399,766	15,127,512	988,563	40,515,841
2018	25,014,774	15,728,631	1,005,831	41,749,236
	202,196,553	129,129,694	9,101,188	340,427,435


PGW Retiree Welfare Plan
Current and Future Retiree Payout Projections
Payout
50,000,000
45,000,000
40,000,000
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2009
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
2031
2033
2035
2037
Year
Future Retirees
Current Retirees

APPENDIX 1

SUMMARY OF RETIREE WELFARE BENEFITS

A. Eligibility

An employee must retire directly from active service in order to be eligible for post retirement welfare benefits. All nonunion and union employees who satisfy the following eligibility requirements will receive post-retirement welfare benefits:

Normal – age 65 and 5 years of service

Early – age 55 and 15 years of service, or 30 years of service

Special Early – Age 55 and 25 years of service

Disability – age 45 and 15 years of service and rule of 65, or 20 years of service

Pre-Retirement Spouse's Benefit – age 45 and 15 years of service and rule of 65, or 20 years of service

If a retiree selects a joint and survivor annuity with his or her spouse as the beneficiary under the pension plan, then the spouse receives lifetime health benefits. Otherwise, spousal coverage stops on the death of the retiree.

B. Health Benefits

a. Medical Benefits

For pre-65 retirees, a choice of plans offered by Independence Blue Cross including Personal Choice Option 1, Blue Cross Blue Shield Major Medical, or Keystone HMO's. Employees who retire after 12/1/01 are provided the Keystone 5 Plan at the company expense and they can buy up to a more expensive plan. Employees who retire after 9/01/07 are provided the Keystone 10 Plan at company expense, and they can buy up to a more expensive plan.

Post-65 retirees are covered by the Independence Blue Cross Security 65 plan.

b. Prescription Drug Benefits

Employees who retired after April 15, 1976 and prior to 12/1/01, are offered a Prescription Plan that has been set up for retirees and is separate from the plan that is set up for active employees. The retiree Prescription plan consists of a $2 copay for generic drugs, a $2 copay for brand name drugs when no generic drugs are available, and a $15 copay for brand name drugs when generic drugs are available. There are no deductibles and no lifetime maximums. Employees who retired prior to 4/15/76 or after 12/1/01 have a $5 copay for generics and a $10 copay for brand drugs. Employees who retire after 9/01/07 pay a $5 copay for generics and a $15 copay for brand drugs.

c. Dental Benefits

For employees who retired after April 15, 1978, a basic dental plan is offered at no cost to the retiree.

For employees who retired after June 1, 1984, an enhanced dental plan is offered. For eligible retirees who enroll in the enhanced dental plan, a contribution of $4.82 per month is required for single coverage and $22.89 per month for employee/dependent coverage. The company pays the additional costs of the enhanced dental plan.

C. Death Benefits

a. Nonunion employees receive death benefit coverage equal to two times salary. At age 65, the death benefit reduces 5% per year for 15 years until the benefit equals 25% of the age 65 death benefit. PGW pays the cost of the first $75,000 of coverage. Retirees pay $0.35 per 1000 for coverage in excess of $75,000.

b. Union employees are offered voluntary life insurance at 1x pay at retirement. Death benefit amount decreases 10% per year for 5 years until 50% of original amount. Retirees pay $0.35 per 1000, PGW pays the rest.

c. Upon the death of an active employee prior to being eligible to retire with medical coverage, surviving spouses and dependents are entitled to receive 2 years of medical coverage paid by PGW.

D. Contributions

PGW pays the full cost of medical, basic dental, and prescription coverage for employees who retired prior to 12/1/01. Employees who retire after 12/1/01 are provided the Keystone 5/Keystone 10 plan at the company expense and can buy up to a more expensive plan. Retirees also contribute toward enhanced dental plan and life coverage as described above. PGW pays 100% of the cost for the prescription drug plan after drug co-pays.

APPENDIX 2

ACTUARIAL ASSUMPTIONS AND METHODS

Assumptions

The actuarial assumptions used to value the postretirement medical liabilities can be categorized into three groups:

- Economic Assumptions – the discount rate and health care cost trend rates.
- Benefit assumptions – the initial per capita cost rates for medical coverage, and the face amount of employer-paid life insurance.
- Demographic assumptions – including the probabilities of retiring, dying, terminating (without a benefit), becoming disabled, recovery from disability, election (participating rates) and coverage levels.

Actuarial assumptions were based on the actual experience of the covered group, to the extent that creditable experience data was available, with an emphasis on expected long-term future trends rather than giving undue weight to recent past experience. The reasonableness of each actuarial assumption was considered independently based on its own merits, its consistency with each other assumption, and the combined impact of all assumptions.

ECONOMIC ASSUMPTIONS

The two economic assumptions used in the valuation are the discount rate and the health care cost trend rates. The economic assumptions are used to account for changes in the cost of benefits over time and to discount future benefit payments for the time value of money.

Discount Rate

The investment return assumption (discount rate) should be the estimated long-term investment yield on the investments that are expected to be used to finance the payments of benefits. The investments expected to be used to finance the payments of benefits would be plan assets for funded plans, assets of the employer for pay-as-you-go plans, or a proportionate combination of the two for plans that being partially funded. We assumed a discount rate of 5.0 percent for purposes of developing the liabilities and Annual Required Contribution on the basis that the Plan would not be funded and with management's concurrence that 5% represents their expected long term yield on general employer investments.

Health care trend rates

Year	Medical (pre-65)	Medical (post-65)	Drug	Dental
1	13.0%	9.0%	9.0%	4.5%
2	12.0%	8.0%	8.0%	4.5%
3	11.0%	7.0%	7.0%	4.5%
4	10.0%	6.0%	6.0%	4.5%
5	9.0%	5.0%	5.0%	4.5%
6	8.0%	4.5%	4.5%	4.5%
7	7.0%	4.5%	4.5%	4.5%
8	6.0%	4.5%	4.5%	4.5%
9	5.0%	4.5%	4.5%	4.5%
10 and beyond	4.5%	4.5%	4.5%	4.5%

MEDICAL ASSUMPTIONS

The valuation projects the cost to PGW of providing medical benefits to employees who remain in the medical plan after retirement (postemployment coverage). PGW offers various medical plans at no cost to the retirees. Retirees can buy up to more expensive plans depending on their retirement dates. We have developed incurred claims costs for the benefits provided by PGW at no cost to the retirees. Following actuarial standards, specifically ASOP 6, leads us to develop age-specific health care cost estimates.

Annual Age Specific Per Capita Claims Cost

Retired prior to September 1, 2009:

	Medical		Prescription Drug *	
Age	Retiree	Dependent	Retiree	Dependent
<50	$3,936	$5,340	$1,524	$1,524
50-54	$4,788	$6,492	$1,680	$1,680
55-59	$5,988	$8,124	$2,112	$2,112
60-64	$7,212	$9,780	$2,532	$2,532
65-69	$1,752	$1,764	$2,988	$2,988
70-74	$2,004	$2,016	$3,420	$3,420
75-79	$2,244	$2,268	$3,840	$3,840
80-84	$2,412	$2,424	$4,152	$4,152
85-90	$2,496	$2,508	$4,320	$4,320
90+	$2,592	$2,616	$4,380	$4,380

Retired on or after September 1, 2009:

Medical				Prescription Drug *	
Age	Retiree	Dependent		Retiree	Dependent
<50	$5,250	$10,436		$1,478	$1,478
50-54	$5,250	$10,436		$1,630	$1,630
55-59	$5,250	$10,436		$2,049	$2,049
60-64	$5,250	$10,436		$2,456	$2,456
65-69	$1,752	$1,764		$2,898	$2,898
70-74	$2,004	$2,016		$3,317	$3,317
75-79	$2,244	$2,268		$3,725	$3,725
80-84	$2,412	$2,424		$4,027	$4,027
85-90	$2,496	$2,508		$4,190	$4,190
90+	$2,592	$2,616		$4,249	$4,249

*PGW has applied for the retiree drug subsidy under Medicare Part D; the above prescription drug costs are not reduced nor do the liabilities reflect any anticipated retiree drug subsidy refund.

Morbidity

The above healthcare costs reflect the following changes due to increased usage as a result of aging:

Age	Annual Increase
65 – 69	3.0%
70 – 74	2.5%
75 – 79	2.0%
80 – 84	1.0%
85+	0.5%

DEMOGRAPHIC ASSUMPTIONS

Mortality
Healthy mortality is assumed to follow the RP2000 Combined Healthy Mortality Table for males and females. Disability mortality is assumed to follow the table specified in IRS Revenue Ruling 96-7 for disabilities occurring after December 31, 1994.

Salary Scale 3.0% for the first three years, then 4.5% thereafter.

Retirement Rates
It is assumed that 10% of eligible participants retire at each age from age 55 to 61. It is assumed that 100% of eligible participants retire at age 62.

Withdrawal
Turnover rates vary by age and service with illustrative rates as follows:

	Years of Service					
Age	0	1	2	3	4	5
20	23.2%	17.4%	14.4%	11.6%	8.8%	5.8%
25	18.8	14.0	11.8	9.4	7.0	4.6
30	14.8	11.0	9.2	7.4	5.6	3.6
35	11.2	8.4	7.0	5.6	4.2	2.8
40	8.8	6.6	5.6	4.4	3.4	2.2
45	7.2	5.4	4.6	3.6	2.8	1.8
50	5.2	3.8	3.2	2.6	2.0	1.2
55	0.0	0.0	0.0	0.0	0.0	0.0

Disability Rates Disability rates vary by age with illustrative rates as follows:

Age	Percent Expected to Become Disabled in the Next Year
25	0.06%
35	0.07
40	0.11
45	0.22
50	0.46
55	1.02
60	1.62

Participation Rates
We have assumed 100% of future retirees will participate in the postemployment welfare plans upon retirement.

Data Assumptions
For retirees, actual data was used for type of coverage and spouse's date of birth. For Active employees, 65% of those who become eligible for coverage at retirement are assumed to have spousal coverage, with wives three years younger than husbands.

Methods

There are several acceptable actuarial methods listed in the GASB standard. The projected unit credit actuarial cost method was used in this valuation to develop the actuarial accrued liability and normal cost. Under the projected unit credit cost method, the present value of benefits is allocated uniformly over the employee's expected working lifetime.

The Actuarial Accrued Liability is that portion of the present value of projected benefits which has been accrued during the employee's working lifetime from hire to valuation date.

The normal cost represents the amount charged for service earned during the current reporting period. The normal cost is calculated by dividing the present value of projected benefits for an employee by the total service. The normal cost amount is expected to increase at the discount rate, currently 5%.

APPENDIX 3

DEMOGRAPHIC CHARACTERISTICS

Demographic data as of March 1, 2009 for current retirees and for active employees was provided by PGW. Information used includes gender, dates of birth, hire and retirement, and coverage status.

		Number	Average Age
1.	Retirees* and Surviving Spouses	1,937	72.9
2.	Active Employees		
	- Union	1,231	45.6
	- Management	510	47.7

*There are 838 retirees with dependent coverage.

Retiree and Surviving Spouse Age Distribution

Age Group	Male	Female	Total
<60	180	102	282
60-64	224	55	279
65-69	154	64	218
70-74	149	74	223
75-79	161	109	270
80-84	181	141	322
85+	165	178	343
Total	1,214	723	1,937

PGW Actives for the 2009 Valuation

Union

	0-4	5-9	10-14	15-19	20-24	25-29	30+	Total
<25	71	2	0	0	0	0	0	73
25-29	60	34	0	0	0	0	0	94
30-34	38	25	0	0	0	0	0	63
35-39	24	30	0	27	1	0	0	82
40-44	19	18	2	29	74	3	0	145
45-49	16	20	1	34	110	66	7	254
50-54	12	8	1	25	76	97	53	272
55-59	3	2	1	9	41	35	61	152
60-64	5	0	0	5	14	27	27	78
65-69	2	1	0	3	2	2	3	13
70-74	0	1	0	0	0	1	1	3
75-79	0	0	0	0	1	0	0	1
80-84	0	0	0	0	0	0	0	0
85+	0	0	0	0	0	0	1	1
Total	250	141	5	132	319	231	153	1,231

Non-Union

	0-4	5-9	10-14	15-19	20-24	25-29	30+	Total
<25	8	0	0	0	0	0	0	8
25-29	23	0	0	0	0	0	0	29
30-34	15	6	0	0	0	0	0	31
35-39	12	15	1	0	0	0	0	23
40-44	21	8	0	2	1	0	0	73
45-49	6	17	3	13	17	2	0	80
50-54	10	13	4	4	24	22	7	148
55-59	5	5	4	9	28	52	40	77
60-64	4	5	6	4	6	18	33	30
65-69	1	4	7	1	1	2	11	9
70-74	0	4	2	0	0	1	1	2
75-79	0	2	0	0	0	0	0	0
80-84	0	0	0	0	0	0	0	0
85+	0	0	0	0	0	0	0	0
Total	105	79	27	33	77	97	92	510

Exhibit SMK-3

PHILADELPHIA GAS WORKS POSTRETIREMENT WELFARE PLAN

Projection of GASB 45 Costs and Other Items Assuming PGW Does Not Fund the ARC

FISCAL YEAR ENDING AUGUST 31:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actuarial Accrued Liability (AAL), BOY	557,944	573,734	591,599	635,792	653,753	670,719	687,220	702,978	717,695	731,019
Interest on AAL	27,897	28,687	29,580	31,790	32,688	33,536	34,361	35,149	35,885	36,551
Normal Cost with Interest	7,179	7,915	8,311	8,793	9,233	9,695	10,180	10,689	11,223	11,784
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Interest on Benefit Payments	(470)	(457)	(501)	(552)	(609)	(652)	(702)	(759)	(824)	(895)
Actuarial (Gain)/Loss During Year	0	0	26,860	0	0	0	0	0	0	0
AAL, EOY	573,734	591,599	635,792	653,753	670,719	687,220	702,978	717,695	731,019	742,677
Market Value of Assets, BOY	0	0	0	0	0	0	0	0	0	0
Contributions	18,816	18,280	20,057	22,070	24,346	26,078	28,081	30,362	32,960	35,782
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Investment Income	0	0	0	0	0	0	0	0	0	0
Market Value of Assets, EOY	0	0	0	0	0	0	0	0	0	0
UAAL	557,944	573,734	591,599	635,792	653,753	670,719	687,220	702,978	717,695	731,019
Normal Cost with Interest	7,179	7,915	8,311	8,793	9,233	9,695	10,180	10,689	11,223	11,784
Amortization of UAAL	37,322	37,322	38,484	41,359	42,528	43,631	44,705	45,730	46,687	47,554
Annual Required Contribution (ARC)	44,501	45,237	46,795	50,152	51,761	53,326	54,885	56,419	57,910	59,338
Interest on Net OPEB Obligation	0	1,284	2,613	3,910	5,256	6,547	7,811	9,034	10,201	11,295
Adjustment to the ARC	0	(1,671)	(3,399)	(5,087)	(6,838)	(8,518)	(10,162)	(11,753)	(13,271)	(14,695)
Annual OPEB Cost (AOC)	**44,501**	**44,850**	**46,009**	**48,975**	**50,179**	**51,355**	**52,534**	**53,700**	**54,840**	**55,938**
Net OPEB Obligation, BOY	0	25,685	52,255	78,207	105,112	130,945	156,222	180,675	204,013	225,893
AOC	44,501	44,850	46,009	48,975	50,179	51,355	52,534	53,700	54,840	55,938
Contributions	18,816	18,280	20,057	22,070	24,346	26,078	28,081	30,362	32,960	35,782
Net OPEB Obligation, EOY	**25,685**	**52,255**	**78,207**	**105,112**	**130,945**	**156,222**	**180,675**	**204,013**	**225,893**	**246,049**

NOTES

Assumes plan will not be funded and discount rate of 5.00% is based on earnings rate of employer general fund assets
Amortization method is based on an open period of 30 years and 5.00%
Cumulative difference between ARC and employer contributions is Net OPEB Obligation and is carried as a liability on the balance sheet
Medicare Part D Retiree Drug Subsidy may be used to reduce employer contributions
Updated to reflect actual retiree costs through 8/31/09

Exhibit SMK-4

PHILADELPHIA GAS WORKS POSTRETIREMENT WELFARE PLAN

Projection of GASB 45 Costs and Other Items Assuming PGW Funds the AOC beginning fiscal year ending August 31, 2011

FISCAL YEAR ENDING AUGUST 31:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actuarial Accrued Liability (AAL), BOY	557,944	573,734	591,599	635,792	455,491	473,040	490,672	508,148	525,205	541,520
Interest on AAL	27,897	28,687	29,580	31,790	37,578	39,026	40,480	41,922	43,329	44,675
Normal Cost with Interest	7,179	7,915	8,311	8,793	5,321	5,760	6,235	6,749	7,306	7,909
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Interest on Benefit Payments	(470)	(457)	(501)	(552)	(1,004)	(1,076)	(1,158)	(1,252)	(1,360)	(1,476)
Actuarial (Gain)/Loss During Year	0	0	26,880	(198,262) *	0	0	0	0	0	0
AAL, EOY	573,734	591,599	635,792	455,491	473,040	490,672	508,148	525,205	541,520	556,846
Market Value of Assets, BOY	0	0	0	0	0	22,394	45,109	67,924	90,594	112,819
Contributions	18,816	18,280	20,057	22,070	45,853	46,119	46,418	46,752	47,127	47,544
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Investment Income	0	0	0	0	887	2,674	4,478	6,280	8,058	9,793
Market Value of Assets, EOY	0	0	0	0	22,394	45,109	67,924	90,594	112,819	134,374
UAAL	557,944	573,734	591,599	635,792	455,491	450,646	445,563	440,224	434,611	428,701
Normal Cost with Interest	7,179	7,915	8,311	8,793	5,321	5,760	6,235	6,749	7,306	7,909
Amortization of UAAL	37,322	37,322	38,484	41,359	41,418	41,326	41,240	41,159	41,086	41,021
Annual Required Contribution (ARC)	44,501	45,237	46,795	50,152	46,739	47,086	47,475	47,908	48,392	48,930
Interest on Net OPEB Obligation	0	1,284	2,613	3,910	8,672	8,672	8,672	8,672	8,672	8,672
Adjustment to the ARC	0	(1,671)	(3,399)	(5,087)	(9,558)	(9,639)	(9,729)	(9,828)	(9,937)	(10,058)
Annual OPEB Cost (AOC)	44,501	44,850	46,009	48,975	45,853	46,119	46,418	46,752	47,127	47,544
Net OPEB Obligation, BOY	0	25,685	52,255	78,207	105,112	105,112	105,112	105,112	105,112	105,112
AOC	44,501	44,850	46,009	48,975	45,853	46,119	46,418	46,752	47,127	47,544
Contributions	18,816	18,280	20,057	22,070	45,853	46,119	46,418	46,752	47,127	47,544
Net OPEB Obligation, EOY	25,685	52,255	78,207	105,112	105,112	105,112	105,112	105,112	105,112	105,112

NOTES

Assumes plan will be funded beginning in the fiscal year ending August 31, 2011 using a discount rate of 8.25%
Amortization method prior to the 2010-11 fiscal year based on an open 30 year period
Amortization method changed to a closed 30 year period beginning with the 2010-11 fiscal year
Cumulative difference between AOC and employer contributions is Net OPEB Obligation and is carried as a liability on the balance sheet
Medicare Part D Retiree Drug Subsidy may be used to reduce employer contributions
Updated to reflect actual retiree costs through 8/31/09
* Change in liability at September 1, 2010 due to change in discount rate to 8.25% to reflect PGW's commitment to fund the AOC beginning September 1, 2010

PHILADELPHIA GAS WORKS POSTRETIREMENT WELFARE PLAN

Projection of GASB 45 Costs and Other Items Assuming PGW
Funds the AOC plus a 5 year amortization of Net OPEB Obligation beginning fiscal year ending August 31, 2011

FISCAL YEAR ENDING AUGUST 31:	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actuarial Accrued Liability (AAL), BOY	557,944	573,734	591,599	635,792	455,491	473,040	490,672	508,148	525,205	541,520
Interest on AAL	27,897	28,687	29,580	31,790	37,578	39,026	40,480	41,922	43,329	44,675
Normal Cost with Interest	7,179	7,915	8,311	8,793	5,321	5,760	6,235	6,749	7,306	7,909
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Interest on Benefit Payments	(470)	(457)	(501)	(552)	(1,004)	(1,076)	(1,158)	(1,252)	(1,360)	(1,476)
Actuarial (Gain)/Loss During Year	0	0	26,860	(198,262) *	0	0	0	0	0	0
AAL, EOY	573,734	591,599	635,792	455,491	473,040	490,672	508,148	525,205	541,520	556,846
Market Value of Assets, BOY	0	0	0	0	0	44,283	88,805	133,343	177,654	221,435
Contributions - AOC	18,816	18,280	20,057	22,070	45,853	44,305	42,796	41,330	39,909	38,537
5 Year Amortization of Net OPEB Obligation	0	0	0	0	21,022	21,022	21,022	21,022	21,022	0
Benefit Payments	(18,816)	(18,280)	(20,057)	(22,070)	(24,346)	(26,078)	(28,081)	(30,362)	(32,960)	(35,782)
Investment Income	0	0	0	0	1,754	5,272	8,801	12,320	15,810	18,382
Market Value of Assets, EOY	0	0	0	0	44,283	88,805	133,343	177,654	221,435	242,572
UAAL	557,944	573,734	591,599	635,792	455,491	428,757	401,867	374,805	347,551	320,085
Normal Cost with Interest	7,179	7,915	8,311	8,793	5,321	5,760	6,235	6,749	7,306	7,909
Amortization of UAAL	37,322	37,322	38,484	41,359	41,418	39,319	37,195	35,043	32,856	30,628
Annual Required Contribution (ARC)	44,501	45,237	46,795	50,152	46,739	45,079	43,430	41,792	40,162	38,537
Interest on Net OPEB Obligation	0	1,284	2,613	3,910	8,672	6,937	5,203	3,469	1,734	0
Adjustment to the ARC	0	(1,671)	(3,399)	(5,087)	(9,558)	(7,711)	(5,837)	(3,931)	(1,987)	0
Annual OPEB Cost (AOC)	44,501	44,850	46,009	48,975	45,853	44,305	42,796	41,330	39,909	38,537
Net OPEB Obligation, BOY	0	25,685	52,255	78,207	105,112	84,090	63,067	42,045	21,022	0
AOC	44,501	44,850	46,009	48,975	45,853	44,305	42,796	41,330	39,909	38,537
Contributions	18,816	18,280	20,057	22,070	66,875	65,327	63,818	62,352	60,931	38,537
Net OPEB Obligation, EOY	25,685	52,255	78,207	105,112	84,090	63,067	42,045	21,022	0	0

NOTES

Assumes plan will be funded beginning in the fiscal year ending August 31, 2011 using a discount rate of 8.25%
Amortization method prior to the 2010-11 fiscal year based on an open 30 year period
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Updated to reflect actual retiree costs through 8/31/09
* Change in liability at September 1, 2010 due to change in discount rate to 8.25% to reflect PGW's commitment to fund the AOC beginning September 1, 2010

TAB

5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

KENNETH S. DYBALSKI

ON BEHALF OF
PHILADELPHIA GAS WORKS

PHILADELPHIA GAS WORKS
DOCKET NO. R-2009-2139884

DECEMBER 2009

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND POSITION WITH THE COMPANY.

A. My name is Kenneth S. Dybalski. My position is Director, Gas Planning & Rates at the Philadelphia Gas Works.

Q. HOW LONG HAVE YOU HELD THIS POSITION?

A. I assumed the position of Director - Gas Planning & Rates in 2006. Prior to this position, I was the Manager of Gas Planning from 2001 to 2006.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. In my present position, I am responsible for developing and coordinating short and long term planning of gas demand, gas supply, raw material expense and revenue; overseeing the preparation of sales, sendout, revenue and fuel expense projections; developing peak day/hour load projections; overseeing the development of the various filings before the Pennsylvania Public Utility Commission (PUC) and Philadelphia Gas Commission (PGC) with respect to the quarterly and annual Gas Cost Rate (GCR) filings, the Integrated Resource Planning Report, and supporting documentation for gas costs related to PGW's Operating Budget before the PGC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I received both a BS and MBA from Temple University in Philadelphia, Pennsylvania.

Q. HAVE YOU EVER PROVIDED TESTIMONY BEFORE THIS COMMISSION?

A. Yes. I submitted testimony in the following proceedings:

- 2007 PGW 1307(f) Annual GCR Filing at Docket R-00072110;
- 2008 PGW 1307(f) Annual GCR Filing at Docket R-2008-2021348;

- 2008 PGW Extraordinary/Emergency Rate Proceeding at Docket R-2008-2073938; and
- 2009 PGW 1307(f) Annual GCR Filing at Docket R-2009-2088076.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

The purpose of my testimony is to describe and support:

1) the process used to develop the sales forecast for the test year;
2) the allocation of the proposed base rate increase by customer class;
3) the Efficiency Cost Recovery Mechanism;
4) PGW's proposal to create an LNG Rate for Liquefied Natural Gas Service;
5) a modification to PGW's Gas Service Tariff for the Weather Normalization Adjustment; and
6) gas supply-related costs in base rates.

II. <u>SALES FORECAST PROCEDURES</u>

Q. WHAT PROCEDURES DID PGW EMPLOY WHEN FORECASTING SALES FOR THE TEST YEAR?

A. The total system-wide demand is a function of the projected gas demand per customer and the anticipated number of customers in each class. In determining customer demand, PGW projects customer usage, giving consideration to significant gains or losses in each of 47 homogeneous groups for the period being projected. PGW's Gas Planning Department attempts to determine for each customer class the level of demand related to experienced temperatures and the level of demand that is not affected by changes in temperature. Within each class the most recent summer and winter usage patterns are established from historical records. Summer data provides each class of customer's non-temperature sensitive load requirements (baseload) which can be expressed in terms of thousands of cubic feet (Mcf) per day, per customer. Similarly, winter data, after removal of the daily baseload level, determines the temperature sensitive load requirements for each class of customer.

This temperature sensitive usage primarily reflects space heating, but also includes such other temperature sensitive usage as water heating attributable to colder water inlet temperatures due to colder ground temperatures and similar process variations, as well as supplementary heating. This overall heating requirement can be expressed in terms of the cubic feet of gas utilized per degree of temperature change on a per customer basis for each separate customer classification. In addition, consideration is given to the variation of customer utilization patterns for space heating over the year, recognizing the transitional fall start-up of heaters, the deep winter period needs and the tapering off and shut-down which occurs in the late spring. These usage patterns, taken in conjunction with anticipated customer counts and average temperature, form the basis of determining customer class and total system demands.

Q. WHAT IS A DEGREE DAY?

A. The term "degree days" quantifies the daily average degrees of temperature below a base level of 65 degrees Fahrenheit and is used as a tool to measure heating requirements, i.e., on a day experiencing an average temperature of 40 degrees Fahrenheit, there would be 25 degree days.

Q. PLEASE EXPLAIN THE USE OF "NORMALIZED" TEMPERATURES.

A. Due to the inconsistencies of weather and weather forecasting techniques, and because test year data are required to reflect "normal" conditions, no attempt is made to predict the specific daily temperatures of the projection period. Instead, PGW has developed a normal monthly temperature pattern by analyzing statistical records of actual temperature patterns over a 30-year period. This pattern reflects 4,412 degree-days annually.

The annual 4,412 degree-days which compose the PGW normal monthly temperature patterns form the basis of the calculation of the temperature sensitive component of demand. Exhibit KSD-1 documents Philadelphia's 30 year monthly degree day history. The application of the above-described baseload and space heating factors and customer counts, when applied to a calendar-based daily temperature pattern, produces a daily total of customer requirements identified as sendout.

Q. AFTER APPLYING THESE FORECASTING PROCEDURES, WHAT SALES VOLUME DID PGW DETERMINE WAS APPROPRIATE FOR THE TEST YEAR?

After considering the relevant factors, it was determined that customer usage would remain static from FY 2009 to FY 2010 (the test year). Therefore, PGW has modeled test year sales based on FY 2008-09 sales experience. As shown on KSD-2 normalized firm sales and firm transportation are 54,155,459 Mcf.

III. <u>ALLOCATION OF PROPOSED RATE INCREASE BY CUSTOMER CLASS</u>

Q. WHAT WERE THE GOALS OF THE COMPANY'S PROPOSED REVENUE ALLOCATION AND RATE DESIGN?

A. The Company's goals in its proposed revenue allocation and rate design were:

- To gradually move the Rate Classes closer to their full cost of service while recovering the additional revenue requirement; and
- To avoid the "rate shock" that would occur if all customers were moved immediately to their full cost of service.

Q. PLEASE DESCRIBE HOW THE COMPANY IMPLEMENTED THESE GOALS.

A. The Company implemented its revenue allocation goals by directing Mr. Gorman to adhere to the following general directives:

1) Observe the principles of gradualism and avoid rate shock by allocating the rate increase in such a way that carefully moves all classes closer to the system rate of return when compared to PGW's 2006 base rate case compliance filing (Docket No. R-00061931). Mr. Gorman prepared Exhibit HSG-7D which shows the relative return for each rate class from the 2006 compliance filing and the presently proposed rate allocation. For each rate class except the Municipal rate class, the relative returns are moving closer to the system rate of return. PGW did not move the Municipal class closer to the system rate of return because simply maintaining the 2006 Municipal relative return at 1.17 already required a reduction in the Municipal rate. It is important to note that in order to move towards the system rate of return, the proposed Residential and Industrial rates increased more than if the rate increase were allocated on an equal percentage basis while the proposed Commercial, Municipal, PHA-GS and PHA rates decreased.

2) Maintain the <u>GTS/IT</u> Rate Class maximum rates at cost basis rates as required by the Commission's decision in PGW's 2006 base rate case.[1]

3) Make no change to <u>Interruptible Sales</u> volumetric rates because these rates are based on the price of alternative fuels.

Mr. Gorman used these directives to produce the proposed rates that are displayed in his testimony, as presented on Exhibit HSG-7C and in Tariff Supplement 36.

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[1] *PaPUC v. PGW*, Docket No. R-00061931 (September 28, 2007).

Q. HOW DID THE COMPANY USE THIS INFORMATION IN ITS PROPOSED RATE DESIGN?

A. The Company specified the following for developing proposed rates for firm sales classes:

1) No changes in Customer charges.

2) Delivery charges were set in order to recover the additional, first year additional revenue requirement and move all classes closer to the system rate of return.

The results of these computations, which also display PGW's Proof of Revenue are presented on Exhibit KSD-3. The proposed rates used to prepare the proof of revenue at the Company's proposed rates, are displayed in Exhibit HSG-7C.

Q. DO THE PROPOSED REVENUE ALLOCATION AND RATE DESIGN MEET THE COMPANY'S GOALS AS YOU STATED THEM EARLIER?

A. Yes, they do. The goals were accomplished as follows:

- To implement a gradual process of moving the rate classes closer to their full cost of service while recovering the additional revenue requirement:
  - This has been accomplished – Exhibit HSG-7D shows that each rate class has made considerable progress toward unity based on relative rates of return while, on an overall basis, PGW's proposed rates will enable it to realize its claimed additional revenue requirement.
- To minimize the impact on low load factor customers:
  - This was accomplished by keeping the Customer Charge the same as at present.
- To avoid the "rate shock" that would occur if all customers were moved immediately to their full cost of service:
  - This has been accomplished by not attempting to progress to unity in one single base rate proceeding.

IV. EFFICIENCY COST RECOVERY MECHANISM

Q. PGW WITNESS CHERNICK DISCUSSES AN EFFICIENCY COST RECOVERY MECHANISM – HOW WILL THAT MECHANISM WORK?

A. Included in Tariff Supplement No. 36 are tariff pages which were originally filed with its DSM petition in April 2009. They are also attached to my testimony as KSD-4. Mr. Chernick has already testified as to the costs which PGW will seek to recover via the mechanism, but I'll discuss the mechanism itself. Essentially, it will be substantially similar to the 1307(f) recovery mechanism which recovers PGW's gas costs. PGW will track the Demand Side Management Program costs[2] specifically related to each customer class as outlined in KSD-4 and seek recovery of the costs from only the customer class to which the costs are related. Additionally, PGW will only seek to recover the costs after they are incurred. For example, PGW will accumulate costs of the implemented DSM measures on a quarterly basis and calculate the lost revenue related to the implemented measures and then seek to recover these costs over the following year. Furthermore, just like the 1307(f) mechanism, PGW will base the per Ccf surcharge on projected sales volume and to the extent that the costs are over or under collected, PGW will also factor in the over or under collection into per Ccf charges in subsequent quarters.

V. LIQUEFIED NATURAL GAS SERVICE – RATE LNG

Q. IS PGW PROPOSING A NEW RATE?

[2] The Surcharge will recover the following costs: 1) the incremental direct program costs; 2) the administrative costs of the energy efficiency program; and 3) the program-related revenue loss.

A. Yes. PGW is proposing to provide liquefied natural gas for customers able to arrange for transportation via truck from its liquefied natural gas facilities.

Q. WHY IS PGW PROPOSING TO OFFER THIS SERVICE?

A. Recently, PGW has received inquiries about the possibility of selling LNG, but not within the context of an off-system sale. Rather, there has been interest in taking possession of the LNG at PGW's liquefied natural gas facilities and transporting the LNG by truck. For example, PGW was contacted by a current PGW customer considering LNG for its vehicle fleet.

Q. IS PGW AWARE OF ANY POTENTIAL CUSTOMERS WHO CURRENTLY HAVE THE ABILITY TO EITHER STORE OR VAPORIZE LNG?

A. No. The inquiries have been limited to parties who are considering projects using LNG but none of these parties have confirmed to PGW that they are proceeding with any of these projects.

Q. WHY THEN DOES PGW PROPOSE A LNG SERVICE AS PART OF THIS FILING?

A. The Company would like to have a tariff provision permitting the sale of LNG in this manner should any of these projects come to fruition in the future. Exhibit KSD-5 provides the proposed tariff pages.

VI. <u>WEATHER NORMALIZATION TARIFF PAGES</u>

Q. WHY IS PGW PROPOSING A CHANGE TO ITS WEATHER NORMALIZATION TARIFF PAGE?

A. PGW's Weather Normalization Adjustment Clause ("WNA") was approved in the Company's 2001 base rate case (*Pa PUC v. PGW*, R-00017034) in order to permit PGW to recover lost margin related to warmer than normal weather or return margin to customers related to colder than normal weather. More specifically, PGW's base rates are based on the average temperatures during a 30 year period but Philadelphia's weather fluctuates from the 30 year average. PGW proposed the WNA because the weather appeared to be trending towards temperatures that were warmer than the thirty year average and PGW was losing margin revenue because base rates were based on sales volumes normalized for 30 year weather. In order to assure that PGW could recover some of the margin lost during warmer than normal weather and, conversely, not permit the Company to collect a margin windfall during colder than normal weather, the parties to the 2001 base rate case reached a settlement permitting PGW's WNA (which was later approved by the Commission).

At the time PGW implemented the WNA, PGW's base rates were based upon the 30 year period ending August 31, 2001 and PGW factored in this 30 year period in its Gas Service Tariff definition of Normal Heating Degree Days. Of course, every time base rates change pursuant to a 1308(d)[3] base rate case, the Normal Heating Degree Day 30 year period changes. Although PGW changed the Normal Heating Degree Days for the WNA calculation in its billing system so that it properly matched the new base rates that were implemented in its last 1308(d) base rate case (i.e. *PaPUC v. PGW*, Docket No. R-00061931), the Company inadvertently did not change the related tariff pages. PGW proposes the following changes to its Gas Service Tariff No. 2 in order to properly define the 30 year Normal Heating Degree Day period:

Page 149:

[3] 66 Pa.C.S.A. 1308(d).

NHDD – normal heating degree days for any given calendar day within a month are based on the thirty year average for the given calendar day based on the thirty year period ~~ended August 31, 2001~~ **applied in the Company's most recent base rate case.**

Page 150:
Normal HDD are calculated for each day of the fiscal year based upon the thirty year average for the thirty year period ~~ended August 31, 2001~~ **applied in the Company's most recent base rate case.**

VII. GAS SUPPLY RELATED-COSTS IN BASE RATES

Q. WHY IS PGW ADDRESSING THIS ISSUE IN ITS BASE RATE FILING?

A. The reason is twofold:

1) The parties to PGW's 2008-2009 Purchased Gas Cost ("PGC") Proceeding incorporated the following into the PGC Settlement Agreement:

> PGW agrees that in its next base rate tariff filing with the Commission, it will provide schedules depicting gas supply-related costs included in base rates for the historic and future test years and the related impact of those costs on base rates. The filing of such schedules does not commit PGW to any position regarding the appropriateness of removing these costs from base rates.

2) The Commission has ordered natural gas distribution companies that do not offer or propose to offer a purchase of receivables program to "include, in its next base rate case … a fully allocated cost of service study by which the Commission can investigate the unbundling of natural gas procurement costs from base rates."[4]

Q. HAS PGW PROVIDED THIS DATA IN THIS FILING?

[4] Ordering Paragraph No. 9 of the September 11, 2008 Order issued in the SEARCH Proceeding (Docket No. I-00040103F0002).

A. Yes, in his exhibit HSG-8, PGW witness Howard Gorman (PGW St. 8) provides the impact on base rates if commodity related bad debt expense and the commodity related PUC assessment were removed from base rates. Additionally, Exhibit HSG-8 also shows the impact on base rates if the PUC assessment is removed entirely from base rates because a pending PUC rulemaking has proposed the recovery of the entire PUC assessment via a surcharge.[5]

Q. ARE THERE ANY OTHER GAS SUPPLY-RELATED COSTS IN BASE RATES?

A. Other gas supply-related costs are minimal. More specifically, if PGW were to parse the employee related costs of gas procurement, the amount would be immaterial. Additionally, PGW does not have any employees who exclusively procure natural gas. The personnel involved with procurement have varied responsibilities such as dealing with PGW's upstream assets (i.e. pipeline and storage capacity) and issues related to firm transportation customers and their suppliers. If PGW's firm customers were to switch to other suppliers, the responsibilities of the aforementioned employees will not decrease because PGW always remains the Supplier of Last Resort ("SOLR"). As part of the SOLR function, PGW maintains the same level of pipeline and storage capacity and assigns it to the natural gas suppliers, therefore, none of the responsibilities related to PGW's upstream assets will diminish. In fact, responsibilities will likely grow in order to deal with capacity assignment issues and the growth in other customer choice related responsibilities.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

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[5] Natural Gas Distribution Companies and the Promotion of Competitive Retail Markets, Docket No. L-2008-2069114, Proposed Rulemaking Order dated March 27, 2009.

A. Yes.

Exhibit KSD-1

Philadelphia Gas Works
Degree Day History

YEAR	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	TOTAL	HTG SEASON (Sept. - May)
1978-79	51	263	492	809	1,014	1,136	552	398	76	19	7	0	4,817	4,791
1979-80	27	328	435	800	986	991	752	309	64	20	8	8	4,728	4,692
1980-81	12	297	628	973	1,154	702	719	265	97	5	0	0	4,852	4,847
1981-82	38	320	542	896	1,189	837	685	389	49	23	0	0	4,968	4,945
1982-83	23	242	463	682	912	811	631	377	112	2	0	0	4,255	4,253
1983-84	42	241	503	965	1,112	741	858	382	128	0	1	2	4,975	4,972
1984-85	68	100	546	676	1,143	839	644	319	93	20	0	0	4,448	4,428
1985-86	40	186	430	953	972	914	607	352	82	9	0	13	4,558	4,536
1986-87	23	222	575	787	988	860	582	344	117	0	0	0	4,498	4,498
1987-88	19	336	485	767	1,089	855	603	413	109	32	0	0	4,708	4,676
1988-89	28	378	474	868	829	828	684	344	146	1	0	0	4,580	4,579
1989-90	47	210	565	1,187	727	650	578	352	115	5	1	1	4,438	4,431
1990-91	51	159	452	705	908	674	598	308	45	12	0	0	3,912	3,900
1991-92	60	228	504	769	883	787	732	408	171	14	1	3	4,560	4,542
1992-93	64	332	537	816	836	946	786	355	59	12	0	1	4,744	4,731
1993-94	73	281	522	868	1,210	932	721	232	159	2	0	2	5,002	4,998
1994-95	23	242	412	718	835	919	583	353	115	6	0	0	4,206	4,200
1995-96	48	179	685	1,013	1,055	859	783	355	192	6	0	0	5,175	5,169
1996-97	42	258	680	766	1,000	678	661	383	154	40	0	0	4,662	4,622
1997-98	45	274	625	825	727	607	588	241	64	7	1	0	4,004	3,996
1998-99	7	188	441	657	884	700	654	297	58	6	0	0	3,892	3,886
1999-00	25	235	403	725	974	738	456	329	75	19	1	1	3,981	3,960
2000-01	57	197	537	1,011	926	728	700	283	66	1	0	0	4,506	4,505
2001-02	51	193	302	633	723	631	548	273	109	8	0	1	3,472	3,463
2002-03	5	282	541	851	1,081	909	597	361	167	31	0	0	4,825	4,794
2003-04	14	249	395	804	1,149	771	564	303	43	13	0	0	4,305	4,292
2004-05	15	236	448	783	984	746	728	246	141	6	0	0	4,333	4,327
2005-06	7	204	413	895	711	758	558	196	77	2	0	0	3,821	3,819
2006-07	9	212	324	575	752	951	557	365	28	1	0	4	3,778	3,773
2007-08	6	80	499	746	842	720	538	211	104	0	0	0	3,746	3,746
30 Year Average	34	238	495	817	953	807	642	325	101	11	1	1	4,425	4,412
Normal Temp Pattern	34	238	495	817	953	807	642	325	101					4,412

NORMALIZED SALES
4412 DEGREE DAYS

Exhibit KSD-2

	ACTUAL 2005-06 (Mcf)	ACTUAL 2006-07 (Mcf)	ACTUAL 2007-08 (Mcf)	Actual 2008-09 (Mcf)	6 & 6 ESTIMATED 2009-10 (Mcf)
Non-Heating					
Residential	1,459,212	1,034,988	815,959	728,833	653,072
CRP	170,406	76,488	48,172	42,817	39,994
Commercial	1,732,812	1,606,237	1,446,864	1,298,692	1,314,572
Commercial AC	-	-	-	11,867	-
Industrial	326,570	300,703	248,965	224,411	215,345
Municipal	280,407	270,728	167,927	179,663	146,486
Municipal AC	-	-	-	5,254	-
Housing Authority	-	-	-	-	-
NGV Firm	197	347	357	485	327
Total Firm Non-Heating	3,969,604	3,289,490	2,728,244	2,492,023	2,369,796
Interruptible					
BPS Small	138,990	131,656	140,799	126,237	93,804
LBS-L Direct	12,859	-	-		-
LBS-XL Direct	5,530	16,740	22,180		-
BPS Large	1,434,847	1,375,624	920,745	857,227	562,907
LBS-L Indirect	147,920	23,524	643	21,246	8,587
LBS-S	375,222	727,791	534,615	99,136	63,584
LBS-XL Indirect	188,569	61,839	24,902	32,805	22,294
CO-GEN Indirect	16,741	12,172	14,309	14,310	9,290
GTS Sales	12,987	270,975	130,046	14,710	-
BPS A/C	92,193	84,204	2,480	4,458	9,694
NGV	-	-	-	-	-
Total Interruptible	2,425,858	2,704,526	1,790,720	1,170,130	770,160
Total Non-Heating	6,395,461	5,994,015	4,518,964	3,662,152	3,139,955
Heating					
Residential	27,756,799	29,469,349	28,710,881	28,062,706	28,793,526
Residential AC	-	-	-	57	-
CRP	8,545,198	9,970,118	10,067,469	10,198,397	10,354,462
Housing Authority - GS	270,440	246,238	137,441	203,752	209,424
Commercial	8,253,980	8,410,686	7,766,286	7,286,256	7,232,733
Commercial AC	-	-	-	4,461	-
Industrial	669,154	629,508	466,075	425,402	454,809
Municipal	975,030	959,237	654,627	614,361	571,935
Housing Authority - PHA	581,350	655,643	699,622	670,498	593,669
Total Heating	47,051,952	50,340,778	48,502,402	47,465,889	48,210,557
Total Firm	51,021,555	53,630,268	51,230,645	49,957,912	50,580,353
Total Gas Sales	53,447,413	56,334,793	53,021,365	51,128,042	51,350,513
Firm Transport					
FT-RES	-	-	11,381	12,847	-
FT-COM	-	467,861	1,079,135	1,445,823	1,906,833
FT-IND	-	92,848	248,885	219,186	318,991
FT-MUN	-	49,665	499,046	471,984	579,123
FT-PHA	-	-	-	-	-
TOTAL	-	610,374	1,838,447	2,149,841	2,804,947
TOTAL & FIRM TRANSPORT	53,447,413	56,945,167	54,859,812	53,277,883	54,155,460
GTS TRANSPORT	10,727,087	12,569,417	17,425,385	20,530,851	19,548,273
TOTAL & ALL TRANSPORT	64,174,500	69,514,585	72,285,197	73,808,734	73,703,732
Degree Days (Sep-May)	3,819	3,773	3,746	4,181	4,412

Philadelphia Gas Works
Allocated Class COS Study - 2009
Revenue at Company's Proposed Rates

		Rate Year 2010			Company's Proposed Rates		Amounts in $000s				
		No. of Customers	No. of Annual Bills	Annual Sales (mcf)	Cust. Charge	Delivery Charge	Cust. Revenue	GCR Revenue	USEC/REC Revenue	Delivery Revenue	Total Full Tariff Rev.
1	**Non-Heating:**										
2	Residential	31,002	372,021	658,616	$12.00	$7.2977	4,464	4,809	1,382	4,806	15,461
3	Residential-Senior	1,942	23,306	34,450	$12.00	$7.2977	280	252	72	251	855
4	Commercial	5,025	60,300	1,314,572	$18.00	$5.0287	1,085	9,598	2,759	6,611	20,053
5	Industrial	206	2,467	215,345	$50.00	$6.4144	123	1,572	452	1,381	3,529
6	Municipal/MS	114	1,368	146,486	$18.00	$3.4344	25	1,070	307	503	1,905
7	*Total Non-Heat Firm*	38,289	459,462	2,369,469			5,977	17,300	4,973	13,553	41,803
8											
9	**Heating:**										
10	Residential	400,307	4,803,683	36,122,041	$12.00	$7.2977	57,644	263,731	75,809	263,608	660,792
11	Residential-Senior	31,728	380,740	3,025,947	$12.00	$7.2977	4,569	22,093	6,351	22,082	55,095
12	Commercial	18,271	219,246	7,232,733	$18.00	$5.0287	3,946	52,807	15,179	36,371	108,304
13	Industrial	510	6,120	454,809	$50.00	$6.4144	306	3,321	955	2,917	7,498
14	Municipal/MS	408	4,891	571,935	$18.00	$3.4344	88	4,176	1,200	1,964	7,428
15	PHA Rate 8	833	9,993	593,669	$18.00	$5.0990	180	4,334	1,246	3,027	8,787
16	PHA/GS	1,889	22,672	202,798	$12.00	$5.1784	272	1,481	426	1,050	3,228
17	PHA/GS- Senior	67	804	6,626	$12.00	$5.1784	9,648	48	14	34	106
18	*Total HeatiFirm*	454,012	5,448,149	48,210,558			67,015	351,990	101,179	331,055	851,239
19	***Total Firm Sales***	**492,301**	**5,907,611**	**50,580,027**			**72,992**	**369,290**	**106,152**	**344,607**	**893,042**
20											
21	**Firm Transport**										
22	**Non-Heating:**										
23	Residential	0	0	0	$12.00	$7.2977	0		0	0	0
24	Commercial	382	4,584	315,313	$18.00	$5.0287	83		662	1,586	2,330
25	Industrial	21	252	50,869	$50.00	$6.4144	13		107	326	446
26	Municipal/MS	218	2,616	123,866	$18.00	$3.4344	47		260	425	732
27	*Total Non Heat FT*	621	7,452	490,048			142		1,028	2,337	3,508
28											
29	**Heating:**										
30	Residential	0	0	0	$12.00	$7.2977	0		0	0	0
31	Commercial	1,190	14,280	1,591,524	$18.00	$5.0287	257		3,340	8,003	11,600
32	Industrial	42	504	268,130	$50.00	$6.4144	25		563	1,720	2,308
33	Municipal/MS	176	2,112	455,256	$18.00	$3.4344	38		955	1,564	2,557
34	*Total Heat FT*	1,408	16,896	2,314,910			320		4,858	11,287	16,465
35	***Total FT***	2,029	24,348	2,804,958			462		5,887	13,624	19,973
36											
37	**Interruptible:**	129	1,546	770,488			94			7,920	8,013
38	**Total PGW**	494,459	5,933,505	54,155,473			73,549	369,290	112,039	366,151	921,029
39	GTS / IT Revenue										9,844
40											
41	**Proposed Tariff Revenue at Full Tariff Rates**										930,872
42	Less GCR Revenue										369,290
43	**Distribution Tariff Revenue at Proposed Rates**										561,583
44									**Target**		42,504
45									**Current Rates**		519,080
46									**Actual Increase**		42,502

EFFICIENCY COST RECOVERY SURCHARGE

The cost of the energy efficiency programs (i.e. the demand side management programs) for the firm customer rate classes listed below will be recovered by an Efficiency Cost Recovery Surcharge applicable to all volumes of Gas delivered.

1) The Surcharge will recover the following costs: 1) the residual direct program costs and the administrative costs of the energy efficiency program; and, 2) the program related revenue loss.

2) Computation of the Efficiency Cost Recovery Surcharge factors will be in accordance with the automatic adjustment procedures utilized under Section 1307(f) of the Public Utility Code and will be filed and approved in conjunction with the Company's annual Section 1307(f)-GCR filing.

3) Once the surcharge is in place, it will be automatically adjusted effective March 1, June 1, September 1, and December 1 of each year in accordance with Section 1307(f) quarterly adjustment procedures. No interest will be included in such surcharge computations. The basic component of the surcharge will be determined by dividing the total energy efficiency program costs approved for annual recovery by the estimated applicable throughput in Mcfs. The costs related to customers other than low income residential customers are tracked and recovered separately from each of the following firm customer rate classes served by the energy efficiency program:

   a) Residential and Public Housing Customers on Rate GS;
   b) Commercial and Municipal Customers on Rate GS;
   c) Industrial Customers on Rate GS;
   d) Municipal Customers on Rate MS; and
   e) The Philadelphia Housing Authority on Rate PHA.

   The surcharge shall be a cents per Ccf charge calculated to the nearest one-thousandth of a cent (0.00001) which shall be added to the distribution rates for billing purposes for all customers in each of the above rate classes. The rate shall be calculated separately for each rate class.

   The energy efficiency program costs related to low income customers shall be incorporated into the Conservation Works Program and recovered through the Universal Services Surcharge.

4) The Efficiency Cost Recovery Surcharge shall take effect upon the effective date of this Tariff.

LIQUEFIED NATURAL GAS SERVICE - RATE LNG

Rate: Applicable to Liquefied Natural Gas Service as described below.

AVAILABILITY

Available at the Company's sole discretion where the Customer is able to arrange for the transportation of Liquefied Natural Gas via truck from the Company's Liquefied Natural Gas facilities.

RATES and TERMS OF SERVICE

Contracts stipulating the negotiated rate and negotiated terms of Liquefied Natural Gas Service may be entered into between the Company and Customer when the Company, in its sole discretion, deems such offering to be economically advantageous to the Company. Service under this rate is interruptible, and the Company reserves the right to interrupt service at Company's discretion.

The Company reserves the right to determine whether the customer will be charged the current Gas Cost Rate (GCR) or the current Weighted Average Cost of Gas (WACOG). The charge will not be less than the current GCR or the current WACOG.

TAB

6

PGW St. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF
RANDALL GYORY

ON BEHALF OF
PHILADELPHIA GAS WORKS
DOCKET NO. R-2009-2139884

December 2009

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Randall Gyory. My business address is 800 West Montgomery Avenue, Philadelphia, PA 19122.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Philadelphia Gas Works ("PGW" or the "Company") in the capacity of Senior Vice President – Operations and Customer Affairs.

Q. WHAT ARE YOUR PRINCIPAL RESPONSIBILITIES AS SENIOR VICE PRESIDENT?

A. My principal responsibilities include Field Services, Distribution Operations, Customer Affairs and Supply Chain.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I attended the University of Pittsburgh and graduated with a Bachelor of Science degree in Engineering in 1979. I accepted a job at PGW shortly after graduation as an Engineering Assistant in the Distribution Department. Since that time, I have held the following positions: Assistant Supervisor (1981); Staff Engineer (1984); Senior Staff Engineer (1988); Major Accounts Manager – Marketing Department (1999); Manager – Program Management Office (2000); and Vice President of Customer Affairs (2001). In 2007, I was promoted to my current position as Senior Vice President – Operations and Customer Affairs.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("PUC")?

A. Yes. I submitted testimony in PGW's Restructuring Proceeding (M-00021612). I also submitted testimony in the Investigation into Financial and Collections Issues Proceeding which was a consolidated proceeding involving PGW's Gas Cost Rate (GCR) filing, PGW's Petition regarding Cash Receipts Reconciliation Clause (CRRC), PGW's Senior Citizen Discount Petition, and PGW's request to approve various tariff provisions. ("Consolidated Proceeding") (P-00042090, et. al.). I also testified before the Commission in the Company's 2006 base rate request (R-2008-2073938) and the Company's 2008 emergency/extraordinary rate case (R-2008-2073938).

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR TESTIMONY.

A. I will introduce and explain PGW's proposed tariff changes in the areas of debt collection and unauthorized usage of service.

PROPOSED TARIFF CHANGES

Q. PLEASE DESCRIBE WHAT TARIFF CHANGE PGW IS PROPOSING REGARDING APPLICANT LIABILITY.

A. After service is terminated at a particular location, PGW is frequently faced with new applicants for residential service who appear to have lived for some time at the premises for which service has been requested or other premises and are attempting to avoid responsibility for the arrearage, or to assist another occupant in avoiding gas debt liability by applying for service as a new applicant. Chapter 14 acknowledges this problem and permits utilities to establish that an applicant previously resided at the location for which he or she is applying for service through the use of a mortgage, deed or lease information, a commercially available consumer credit reporting service or other methods as approved as valid by the Commission. Through our proposed tariff revision, PGW is seeking to prove occupancy through the following methods in addition to those specifically identified in Chapter 14:

1) a driver's license or other government issued identification card which requires an address update, including, but not limited to a Commonwealth or State issued Driver's License, Learner's Permit or Identification Card;
2) a Commonwealth or State issued vehicle registration;

3) federal, state or Commonwealth tax records;
4) a CRP application;
5) a medical certificate;
6) a filed PUC complaint;
7) a Crisis/LIHEAP application;
8) a bankruptcy petition; and
9) a personal check.

Q. WHY IS PGW PROPOSING TO UTILIZE THESE OTHER METHODS TO ESTABLISH PRIOR OCCUPANCY?

A. Allowing prior customers to avoid liability for arrearages that were incurred for gas service which benefitted them increases PGW's uncollectibles, places unnecessary burdens on customers who pay their bills, and is unfair to those paying customers. As just one example of how this can occur, in 2006, an applicant applied for service at a particular location which had a prior arrearage of almost $1,000 and had service terminated twice including once for unauthorized use. While the prior service had been provided under a different name (subsequently determined to be the new applicant's fiancée), the applicant claimed that he had just moved in the month before and provided a recently dated sales contract for the property as proof. PGW determined from the driver's license of the applicant that he had used the premises as his residence since at least December 2005 and PGW assigned liability to the applicant. While this assignment was ultimately upheld as a result of a subsequent informal complaint filing, the Bureau of Consumer Services, nonetheless, cited PGW for its reliance on the driver's license to establish residency. Without the ability to utilize all legitimate methods to establish prior occupancy, such as a state issued driver's license which legally must show the current residence, PGW's ability to assign appropriate cost responsibility is unnecessarily limited. Ultimately, all other customers will pay for such uncollectibles – which is not an appropriate or necessary result.

Q. PLEASE EXPLAIN HOW PGW ADDRESSES THIS PROBLEM CURRENTLY.

A. PGW uses the applicant's social security number to access credit reporting information for an applicant from a nationally recognized credit reporting agency when the application for service is received. This agency provides residence data and verifies the identity of the applicant. If the credit report shows that the applicant resided or resides at the address for which service is requested, then the prior arrearage for the period during which he/she resided there will be assigned to the applicant. If the applicant disputes this assignment, or if there is some other reason to question the validity of the assertion, PGW will ask to examine additional information, but is not currently authorized to use the documents or sources of information listed in this tariff change proposal, thus limiting use of reliable sources of information that would have probative value.

Q. WHY DOES PGW BELIEVE IT IS APPROPRIATE TO EXPAND THE FIELD OF DOCUMENTS IT CAN EXAMINE TO DETERMINE PRIOR OCCUPANCY?

A. In addition to the reason I stated above, that all customers are harmed when bill responsibility cannot be assigned appropriately, Chapter 14 of the Public Utility Code contemplates that additional tools are appropriate to remedy consumer abuse of the system. Section 1407(d) states that "A public utility may also require the payment of any outstanding balance or portion of an outstanding balance if the applicant resided at the property for which service is requested during the time the outstanding balance accrued and for the time the applicant resided there." Section (e) states that a public utility may establish previous residence "through the use of mortgage, deed or lease information, a commercially available consumer credit reporting service or other methods approved as valid by the commission." PGW believes that its proposed list of documents is verifiable and legitimate proof of residency. A driver's license is a government-issued document which is based on information supplied by that individual and gives the person's legal residence and the date on which the license was issued, and must be updated if that residence changes. Applicants who do not have a driver's license usually have other similar government-issued identification that shows the applicant's address and the date on which the card was issued, and which requires updating if the residence changes. Such documents include a PennDOT issued Identification Card or a vehicle registration card. Certain types of company records are also valid ways to verify residency. For example, a LIHEAP or CRP application, which is signed and validated by the applicant, requires the applicant to state his/her residence. Other types of customers' record data that have similar indices of reliability include a medical certificate, a filed PUC complaint, a bankruptcy petition, a personal check and income tax records. All of these documents can provide verification of occupancy and are appropriate for PGW to utilize for this purpose. Moreover, applicants disputing the result of PGW's use of these documents to establish residency can challenge that finding through a complaint with the Commission. Enabling PGW to rely on more, rather than less, verifiable information is an appropriate way to ensure that those who use PGW's service are held responsible for paying for them.

Q. PLEASE DESCRIBE THE SPECIFIC CHANGE YOU ARE PROPOSING.

A. The additions we propose for Section 2.1.A. of our tariff are underlined below:

2.1.A. How to Apply. Application for Gas Service shall be made by telephone, mail<u>, on-line</u> and/or by personal visit to one of PGW's Customer Service Centers, provided however that, an in-person application interview may be required for any Applicant at the discretion of the Company. Gas Service will be provided as soon as possible upon completion of an application. Applications will be considered completed only upon compliance with all PGW requirements. The Company may require payment of any outstanding balances or portion of outstanding balances for properties at which Applicant resided during the time the outstanding balance accrued and for the time the Applicant resided there. The Company may establish that an Applicant previously resided at a property through the use of any of the following:

(i) mortgage, deed or lease information
(ii) a commercially available consumer credit reporting service
(iii) a driver's license or other government issued identification card which requires an address update, including, but not limited to a Commonwealth or State issued Driver's License, Learner's Permit or Identification Card
(iv) a Commonwealth or State issued vehicle registration
(v) federal, state or Commonwealth tax records
(v) a CRP application
(vi) a medical certificate
(vii) a filed PUC complaint
(viii) a Crisis/LIHEAP application
(ix) a bankruptcy petition
(x) a personal check

Q. WHAT CHANGE IS PGW PROPOSING REGARDING LOCATION OF METERS?

A. In its current tariff, PGW retains the discretion as to where to locate its meters or other company equipment to provide service. In many instances, one location is necessary (inside as opposed to outside, or vice versa) for safety, access, zoning/historical, financial or other reasons. Generally, PGW does not relocate a meter except upon customer request or for safety/regulatory reasons. However, when equipment is located inside a customer's premises, the customer may improperly use this location as an opportunity to tamper with the equipment and steal service (i.e. unauthorized usage). When feasible and in cases of theft of service in this manner, particularly in instances of repeated theft, it may be appropriate for both safety and public policy reasons to require that the meter be relocated outside. Other ratepayers should not have to bear the costs of such a meter relocation necessitated by theft. PGW proposes that its tariff give it discretion to require that a meter be relocated outside the building in instances of theft at the meter, at the expense of the unauthorized user. With this change in its tariff, PGW would have an improved ability to both ensure public safety and block efforts to steal utility service.

Q. PLEASE DESCRIBE THE SPECIFIC CHANGE YOU ARE PROPOSING.

A. We propose to add the following language to the end of Section 9.5 of our tariff in addition to the two identified grammatical changes:

> 9.5. LOCATION OF METER AND ACCESSIBILITY OF COMPANY OWNED GAS DELIVERY FACILITIES. The meter(s) or other equipment of the Company which may be necessary for the fulfillment of contracts for Gas should normally be installed at an outside, above ground meter location when suitable protection from outside forces, availability of space and other conditions permit. A meter cover or housing is required if, in PGW's judgment, conditions require physical protection for the meter installation. Where, in PGW's judgment, it is physically and economically unfeasible to do so, PGW may choose to install the meter inside a building in a dry, well-ventilated location not subject to excessive heat and not less than three feet from any source of ignition and/or otherwise suitable place ~~and~~ <u>which</u> shall be conveniently accessible; the Gas Service entrance shall also be accessible to PGW. The meter shall also be as near as possible to the point where the service supply pipe enters the Customer's premises~~:~~ except when, in PGW's judgment, this is not practical or desirable. <u>If PGW's meter has been tampered or interfered with, PGW may, in its sole judgment and where physically feasible, elect to move the meter from inside a building to an outside, above ground meter location and may charge the Customer being supplied through such equipment the costs and expenses of moving the meter.</u>

Q. PLEASE SUMMARIZE WHY PGW'S TWO PROPOSED TARIFF REVISIONS ARE APPROPRIATE.

A. Consumers who fail to bear responsibility to pay for utility service that they have received create a significant financial burden for PGW's paying customers and, in the case of theft of service, increase safety risks. In these instances, it is unfair to require customers to pay for someone else's use of service. These two tariff changes will strengthen PGW's ability to combat these problems. This result is in the best interest of PGW's ratepayers.

Q. DOES THAT COMPLETE YOUR DIRECT TESTIMONY?

A. Yes it does.

TAB

7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

CRISTINA COLTRO

ON BEHALF OF
PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

December 2009

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cristina Coltro and my business address is 800 W. Montgomery Avenue, Philadelphia, PA 19122.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Philadelphia Gas Works ("PGW" or the "Company") as the Vice President-Customer Affairs.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Masters Degree in Energy Management and Policy from University of Pennsylvania, 1995, and a Bachelor's Degree in Economics from Hunter College, City University of New York, 1992. My professional experience includes more than 15 years of working in the field of low-income energy programs and regulatory compliance.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES AS VICE PRESIDENT-CUSTOMER AFFAIRS?

A. My principal responsibilities include the oversight of PGW's Call Center Operations, Credit and Collections, Customer Service Centers, Account Management Department, Billing System, Bill Preparation & Mail Receipts, Regulatory Compliance (Universal Services, PUC Complaints, Dispute Resolution, and Training), and Commercial Resource Center.

Q. HAVE YOU EVER PROVIDED TESTIMONY TO THIS COMMISSION BEFORE?

A. Yes, I have testified before the Commission in the Company's prior base rate requests (in 2001 at R-00006042, in 2002 at R-00027034, in 2006 at R-00061931, in 2008 at R-2008-2073938) as well as the Restructuring Proceeding (M-00021612) and the Consolidated Investigation (P-00042090).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to: (1) describe PGW's existing universal service programs (including a change that occurred since the last rate case); (2) provide my projection of the number of customers who will be enrolled in PGW's CRP program at the end of the test year; and (3) discuss the data available concerning potential cost-offsets when a customer permanently enrolls in PGW's CRP program.

II. <u>UNIVERSAL SERVICE PROGRAMS</u>

Q. PLEASE OUTLINE THE UNIVERSAL SERVICE PROGRAMS AVAILABLE TO PGW CUSTOMERS.

A. PGW has been in the forefront of providing services to low-income customers since the 1990's. For decades, PGW has offered payment assistance and energy conservation programs to its low-income customers. PGW submitted its first Universal Service Plan in September 2003 to the Commission and PGW's current Universal Service and Energy Conservation Plan for the period of 2008 to 2010 was approved by the Commission on August 31, 2007 (Docket No. M-00072021). Program components include the Customer Responsibility Program ("CRP"), the Conservation Works Program ("CWP"), the Customer Assistance Referral Evaluation Program ("CARES"), Low-Income Home Energy Assistance Program ("LIHEAP") Outreach, Hardship Fund through the Utility Emergency Services Fund ("UESF"), and the Senior Citizen Discount Program.

Through these programs, PGW has been successful in keeping thousands of low-income residents and seniors on the system, with affordable gas bills, while seeking to maximize individual contributions from those customers, considering the economic realities in which they find themselves. Over the past eighteen years, the CRP has matured into one of the largest low-income customer assistance programs in the industry.

A. Customer Responsibility Program ("CRP")

Q. PLEASE DESCRIBE PGW'S CURRENT CRP PROGRAM.

A. CRP is a percent-of-income customer assistance program designed to offer affordable and discounted payment plans to low income customers with gross household income at or below 150% of the Federal Poverty Level ("FPL"). The program was implemented in 1994 as an extension of the pilot Energy Assistance Program that had been created in 1989. With some modifications, it was approved by the Commission in 2003. The program has a current participation level of 81,100 low-income customers and there are no restrictions on the number of customers on CRP.

In summary, the CRP program is offered to residential heating and non-heating customers. Participants pay a CRP budget amount that is based on a percentage of household income and occupancy plus $5 co-pay toward pre-program arrears. Participants receive a discount that is defined as the difference between the actual gas bill minus the CRP budget amount and they receive 1/36th arrearage forgiveness of their pre-program arrears for each month paid on time and in full. Thus if customers participate in the CRP and pay their bills on time and in full for three years, all pre-program arrearage would be removed.

Participants who fall between 0-50% of the FPL are asked to pay 8% of their gross monthly income plus a minimum payment of $25/month; customers whose income falls between 51 - 100% of the FPL pay 9% of gross income; and customers whose income falls between 101-150% of the FPL are required to pay 10% of their monthly gross household income. Participant responsibilities include: making payments in full and on time; applying for the LIHEAP grant each year (if eligible); reporting any change of income and/or occupancy, accepting conservation measures offered by PGW; and recertifying annually (unless the customer received a LIHEAP grant during the current program year).

Q. PLEASE COMPARE PGW'S CRP WITH A CAP PROGRAM.

A. PGW's CRP is a type of CAP that falls within the Percentage of Income type of plan recognized by the Commission. As noted, PGW's current program was reviewed and approved by the Commission in 2007 as compliant with all applicable statutes, regulations, and policy statements.

Q. DOES PGW EXPECT CRP PARTICIPATION TO INCREASE?

A. Yes. In Exhibit CC-l, I have set out the annual levels of CRP participants for the last two fiscal years which shows an average increase in participation. Based upon historical trends, PGW is projecting that, by the end of the test year, (FY 2010), there will be approximately 84,000 customers enrolled in the CRP program which represents an average increase of approximately 5,000 customers. I have provided the projection to Mr. Bogdonavage for the purposes of developing his test year financial projections.

Q. HOW DOES PGW RECOVER THE COST OF THE CRP DISCOUNTS PROVIDED TO LOW INCOME CUSTOMERS?

A. The cost of CRP discounts is recovered through its Universal Service and Energy Conservation Surcharge ("USEC" also commonly referred to as "USC") which is paid by all firm customers. Computation of the USEC is made in accordance with the automatic adjustment procedures pursuant to the Public Utility Code and the USEC is adjusted quarterly.

Q. HOW DO LIHEAP CASH GRANTS IMPACT THE DISCOUNT PROVIDED THROUGH CRP?

A. The Low Income Energy Assistance Program (LIHEAP) is a federally funded program administered by the Commonwealth of Pennsylvania through the Department of Public Welfare ("DPW"). Prior to the 2009-2010 heating season, LIHEAP Cash grants received by eligible CRP customers were used to reduce the USEC that all non-CRP firm customers were required to pay to fund CRP. A requirement of the CRP program was that customers had to apply for LIHEAP cash grants (if eligible). When the payment was received, it was posted to the customer's account but immediately backed out. The grant was then used to offset the total amount non-CRP customers had to pay pursuant to the USEC. This Commission-approved methodology had to be changed for the 2009-2010 heating season because of directives imposed on PGW by DPW to apply the cash grants to the accounts of the recipients. The DPW-driven change was approved by the Commission in an order in October 2009.

Q. PLEASE PROVIDE MORE DETAILS ABOUT THE CHANGE ORDERED BY DPW.

A. Beginning in late October 2008, DPW and PGW engaged in months of discussions and meetings about how PGW applied the LIHEAP cash grants to offset the USEC.[1] Ultimately, DPW directed PGW to apply the cash grants directly to current or past due CRP bills (i.e. the "asked to pay" amount). DPW refused to consider any alternative proposal and made clear that if PGW refused to comply it could lose its vendor status for LIHEAP grants. If this had happened, there would have been a loss of assurance that customers directly receiving the cash grants would have used them for timely payment of natural gas bills, thus increasing the risk of termination for non-payment. One result of such shut-offs, aside from the dislocation and suffering of the affected families, would have been that PGW would have experienced increased uncollectibles which are ultimately paid by non-CRP customers. Loss of LIHEAP vendor status could have also negatively affected both CRP and non-CRP customers' ability to quickly use grants to resolve emergencies. Such results would have had serious negative consequences for PGW's low income customers as well as for the Company.

Q. HOW DID PGW RESPOND TO DPW'S REQUIREMENT THAT IT CHANGE HOW LIHEAP CASH GRANTS WERE CREDITED?

A. PGW filed a Petition with the Commission seeking to amend its CRP program to accommodate DPW's directives. In October 2009, the Commission approved PGW's proposal to modify its CRP program for the 2009-2010 season to comply with DPW's directives. (Docket No. M-00072021).

Q. IS PGW PROPOSING ANY MODIFICATIONS TO ITS EXISTING CRP PROGRAM AT THIS TIME?

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[1] DPW never asserted that the method for application of Crisis grants to CRP accounts required modification. PGW applies Crisis grants to the recipient's account.

A. No, however, PGW will propose future adjustments to CRP in a separate filing to be made no later than January 31, 2010 with the goal of enabling the Commission to render a decision no later than the last public meeting in August 2010. PGW agreed to this process as part of the settlement addressing the applicability of LIHEAP cash grants for the 2009-2010 heating season. PGW's current Universal Service Program authorization expires in 2010. We have retained the Applied Public Policy Research Institute for Study and Evaluation ("APPRISE") to review the program, with the mandated DPW changes, and analyze various options for changing the existing program. Those options and PGW's proposed changes will be reviewed as described above.

B. LIHEAP Outreach Program

Q. PLEASE DESCRIBE PGW'S LIHEAP OUTREACH PROGRAM.

A. As I just explained, LIHEAP funds are an integral part of PGW's universal service program. For this reason, PGW engages in an aggressive LIHEAP Cash and Crisis outreach campaign during each heating season. PGW's goal is to maximize the number of grants and funds received in order to assist as many eligible customers as possible.

Q. WHAT ARE PGW'S CURRENT LIHEAP OUTREACH ACTIVITIES?

A. PGW is committed to implementing an extensive outreach campaign to contact all of its customers who are potentially eligible for a LIHEAP grant. Our goal is to encourage each customer to apply for and assign a LIHEAP grant to PGW in order to, among other things, provide PGW customers with financial assistance in meeting their gas bill needs this coming winter.

PGW's Outreach program includes:

- Mailing of post cards to all potentially eligible customers;
- Distribution of flyers (English and Spanish) to many organizations throughout the City;
- Outbound and Inbound phone campaigns;
- LIHEAP Cash intake at PGW's Customer Service Centers;
- Field Visits;
- Information on PGW's Website;
- Radio and newspaper ads;
- Participation in Community Events; and
- Public Announcements & Press Releases.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE EFFECTIVENESS OF OUTREACH THIS YEAR?

A. Yes. For reasons that we do not yet fully understand, receipts from the LIHEAP program are substantially below last year's level at this time. DPW has made substantial changes to this year's program, but we do not yet know whether that is the reason for the decline in grants and we do not yet know how the change is affecting customers. We do know that as of December 9, 2009 we are approximately $8.8 million and 21,500 grants below last year and that many families who were shut off for non-payment have failed to restore. Our LIHEAP outreach is as aggressive as it has ever been.

C. <u>Conservation Works Program ("CWP")</u>

Q. PLEASE DESCRIBE PGW'S CWP PROGRAM.

A. The Conservation Works Program ("CWP"), implemented in 1990, was designed to provide cost-effective weatherization measures to customers who are participants in the CRP, and whose usage exceeds the average usage of CRP customers living in similar households. The CWP focuses on PGW's low-income customers, addressing the main factors that influence their energy usage (such as mechanical and structural systems), and behavioral issues. The goals of the CWP program consist of reducing the gas usage of low-income households in a cost-effective manner, lowering gas bills and improving the payment practices of participating customers.

On average, 2,800 houses are treated each year for approximately $780 each. The primary measures that may be provided by the CWP include:

- Diagnostic audits;
- Energy education;
- Energy-related home repair;
- Programmable Thermostats with automatic clocks;
- Blower door guided shell tightening;
- Water heater wrap and pipe insulation;
- Furnace filters or radiator reflectors;
- Hot water conservation devices - e.g., aerators and showerheads; and
- Roof insulation.

The program has been evaluated and has been determined to be cost-effective. PGW also has a pilot program to assess the efficacy and cost-effectiveness of expanding the treatments in each home. The pilot treatments began in 2006 with the goal of servicing approximately 100 homes. PGW expends approximately $2 million annually for its CWP program. This amount is recovered through PGW's Universal Service Charge.

Q. DOES PGW HAVE OTHER PLANS TO IMPLEMENT CONSERVATION MEASURES?

A. Yes. As part of PGW's Demand Side Management Program, PGW is proposing to expand the CWP to provide services to a greater number of low income customers.

D. Hardship Fund

Q. PLEASE DESCRIBE PGW'S HARDSHIP FUND.

A. PGW provides hardship funds through the Utility Emergency Service Fund (UESF). PGW directs company and customer contributions to UESF in order to match grants of up to $750 to eligible customers whose household income is at or below 175% of the FPL. Other requirements for receiving a grant are: the customer has not received assistance from UESF in the past 24 months; the customer has applied for LIHEAP Cash and Crisis grants if the programs were open; the customer has had his/her service terminated or has received a service termination notice from their utility; and a $750 grant (plus the customer's contribution or a contribution received from another source) will eliminate the customer's arrearage. PGW solicits contributions to the UESF and to the Dollar Plus program at least two times per year via bill inserts, yearly events such as Book Sales, and through customer contact. These contributions are forwarded to UESF to provide additional grants.

E. CARES Program

Q. PLEASE DESCRIBE PGW'S CARES PROGRAM.

A. PGW began offering the Customer Assistance Referral and Evaluation Program ("CARES") in September 2003. CARES is designed to help customers with special needs, such as those who have recently experienced a family emergency, divorce, unemployment, or a medical emergency. This program provides the customer with a variety of referrals to help with bill payment. Information on CARES is provided through various outreach programs.

Q. WHAT KINDS OF ASSISTANCE ARE OFFERED PURSUANT TO THIS PROGRAM?

A. There are two types of assistance:

- "Quick-Fix" assistance offered by customer service representatives in the call center or Customer Service Centers. When customers are identified as special need, the representatives refer customers to both internal and external assistance programs.

- "Case Management" assistance offered by PGW's Universal Services department when the customer needs more assistance than just a referral. When necessary, the Universal Service representatives will work directly with the customer to attain assistance from outside agencies.

F. Senior Citizen Discount Program

Q. PLEASE DESCRIBE PGW'S SENIOR CITIZEN DISCOUNT PROGRAM.

A. The Senior Citizen Discount program offers a 20% bill discount to eligible senior citizen participants. To receive the discount under this program, the customer of record must have been enrolled before September 1, 2003 or have been 65 year old and a member of a household that received the discount as of that same date. No income eligibility is required. There are currently approximately 35,000 participants in this program.

Q. IS PGW ADDING CUSTOMERS TO ITS SENIOR CITIZEN DISCOUNT PROGRAM?

A. No. The program has been closed since August 31, 2003 and no new members have been added since that date pursuant to an order of the Commission.

G. Use of Community-Based Organization

Q. DOES PGW USE COMMUNITY-BASED ORGANIZATIONS AND ADMINISTERING AGENCIES IN CONNECTION WITH UNIVERSAL SERVICE PROGRAMS?

A. PGW manages and administers its low-income programs internally, with its own staff. PGW has six Customer Service Centers throughout the City. These Centers are responsible for intake, recertification, and customer education. Nonetheless, PGW works closely with City agencies and community based organizations including the Neighborhood Energy Centers in order to educate and provide information on available programs.

III. NET CHANGES IN CRP PARTICIPATION LEVELS

Q. IN PGW'S 2006 BASE RATE CASE, THE COMMISSION DIRECTED PGW TO COLLECT DATA TO DETERMINE THE NET CHANGE IN CRP PARTICIPATION AND THE AVERAGE SHORTFALLS FOR ITS CRP PARTICIPANTS. HAS PGW COMPLIED WITH THIS DIRECTIVE?

A. Yes and PGW has provided this information to the Commission as a part of its quarterly GCR filings.

Q. PLEASE SUMMARIZE THE PURPOSE OF THIS REPORTING.

A. In the context of PGW's 2006 rate case, OCA expressed a concern regarding PGW's recovery of bad debt expense. PGW recovers bad debt expense through its base rates as approved by the Commission. PGW recovers the costs of its universal service program through the USEC which is adjusted quarterly. OCA opined that if significant numbers of non-CRP customers were moved into CRP (beyond the numbers projected in the rate case), then PGW would recover the bad debt expense associated with those customers even while recovering the costs associated with these customers as CRP customers through the quarterly adjusted USEC. The Commission directed PGW to provide data with each quarterly reconciliation filing showing the real-time participation levels in CRP. By including it with these filings, the Commission evidently concluded it could consider the information when deciding whether to make future changes in PGW's USEC. That information is included as Exhibit CC-2 to my testimony.

Q. TO YOUR KNOWLEDGE, HAS THE COMMISSION REJECTED OR ALTERED ANY OF PGW'S QUARTERLY GCR FILINGS TO ACCOUNT FOR THIS ISSUE?

A. No.

Q. DOES PGW PROPOSE TO IMPLEMENT A MECHANISM TO ADJUST ITS BAD DEBT EXPENSE FACTOR ON A REGULAR BASIS?

A. The bad debt expense factor contains a variety of calculations and considerations beyond the movement of customers in and out of CRP and this factor is reset with each rate case. A rate case proceeding is the more appropriate time to address how the issue of movement in and out of CRP, in combination with all the other relevant factors, should be factored into arriving at the appropriate bad debt expense factor for going forward rate setting purposes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Actual CRP Participation

Fiscal	Sept	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Avg
FY07-08	74,956	74,915	75,142	76,235	77,603	78,678	79,399	80,958	80,807	79,860	77,828	76,603	77,749
FY08-09	75,819	75,633	76,607	78,490	79,615	81,495	83,047	84,783	85,487	84,726	82,861	82,134	80,891
FY09-10	81,483	81,078	83,000*	84,500*	85,500*	86,000*	86,500*	86,500*	86,000*	85,000*	84,000*	84,000*	84,464

Fiscal Year	Avg
FY08	77,749
FY09	80,891
FY10*	84,464*

*Projected

Exhibit CC-2

PHILADELPHIA GAS WORKS
CRP Participation & Average Shortfall Per CRP Participant
December 2007 to June 2009

	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08
CRP Participation									
Average participation rate (Actual)	76,235	77,603	78,678	79,399	80,958	80,807	79,860	77,828	76,603
Rate case participation rate	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)
CRP Over (Under) participation	(265)	1,103	2,178	2,899	4,458	4,307	3,360	1,328	103
Average Shortfall Per CRP Participant									
CRP Discount	$ 16,592,129	$ 22,100,760	$ 19,268,129	$ 18,702,409	$ 11,380,037	$ 2,178,153	$ (400,339)	$ (1,140,719)	$ (2,176,906)
Average participation rate	76,235	77,603	78,678	79,399	80,958	80,807	79,860	77,828	76,603
Average shorfall per CRP participant	$ 218	$ 285	$ 245	$ 236	$ 141	$ 27	$ (5)	$ (15)	$ (28)

	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09
CRP Participation												
Average participation rate (Actual)	75,819	75,633	76,607	78,490	79,615	81,495	83,047	84,783	85,487	84,726		
Rate case participation rate	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)	(76,500)		
CRP Over (Under) participation	(681)	(867)	107	1,990	3,115	4,995	6,547	8,283	8,987	8,226		
Average Shortfall Per CRP Participant												
CRP Discount	(2,019,274)	(616,103)	1,493,431	21,643,008	29,506,857	28,095,299	19,333,334	10,522,599	2,481,813	(1,778,422)		
Average participation rate	75,819	75,633	76,607	78,490	79,615	81,495	83,047	84,783	85,487	84,726		
Average shorfall per CRP participant	(27)	(8)	19	276	371	345	233	124	29	(21)		

TAB

8

PGW St. 8

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

HOWARD S. GORMAN

ON BEHALF OF PHILADELPHIA GAS WORKS

Docket No. R-2009-2139884

December 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Howard Gorman. I am a Principal Consultant with Black & Veatch Corporation ("Black & Veatch"). My business address is 898 Veterans Highway, Hauppauge, NY 11788.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. My educational background and professional experience are outlined in my curriculum vitae that is attached as Attachment A.

Q. PLEASE BRIEFLY DESCRIBE THE SCOPE OF YOUR ENGAGEMENT WITH PGW AND THE PURPOSE OF YOUR TESTIMONY.

A. Black & Veatch has been retained by Philadelphia Gas Works ("PGW" or "Company") to perform an unbundled, fully allocated class cost of service study (generally, a "CCOSS" and the particular CCOSS that I address in this testimony, the "PGW CCOSS") as part of its present filing before the Pennsylvania Public Utility Commission ("PaPUC" or "Commission"). One of the purposes of a CCOSS is to assign the total costs and other items of the revenue requirements of the Company to each Rate Class. The costs assigned to each Rate Class can then be compared to the revenue produced by the rates in the Company's current Gas Rate Tariff ("Tariff"), as well as to the rates proposed by the Company in this proceeding.

I also present the results of a cost of service analysis of PGW's Interruptible Transportation service, which is based on the PGW CCOSS.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION ON BEHALF OF PGW?

A. Yes, I testified before the Commission on behalf of PGW in the following dockets:

- Dockets R-00061931 (Dec. 2006), R- 00017034 (Feb. 2002) and R-00006042 (Jan. 2001)- Prepared and sponsored PGW's fully allocated class cost of service studies
- Docket M-00021612 (July 2002)- Supported PGW's restructuring

Q. WHAT WAS THE SOURCE OF THE INFORMATION THAT YOU USED IN PERFORMING THIS ENGAGEMENT?

A. All of the information about PGW's operations was provided by PGW, and I relied on the genuineness and completeness of all information presented to me by PGW. Costs and other data were provided by PGW for the Test Year (the Fiscal Year ending August 31, 2010), including a limited number of pro forma adjustments. These data included forecasted test year total system costs of service, forecasted sales and transportation volumes, forecasted customer information and forecasted revenues. In addition, other operating and plant information was supplied by PGW for the purpose of cost classification and the development of direct cost assignments and allocation factors that are required to perform the cost allocation study. The budget was prepared by PGW on the assumption of normal weather. The revenue requirements are set forth in the testimony of Company witness Mr. Bogdonavage.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section 1, I provide background information and identify the exhibits that I am sponsoring. In Section 2, I discuss the Class Cost of Service Study methodology. In Section 3, I present the results of the CCOS and discuss the contents of the exhibits. In section 4, I describe the computations that I performed based on the Company's specifications for revenue allocation and proposed rates. In section 5, I address the question of what gas-supply- related costs are included in base rates.

SECTION I – BACKGROUND INFORMATION

Q. PLEASE STATE PGW'S NON-GAS TARIFF REVENUE REQUIREMENT FOR THE TEST YEAR.

A. Based on the Test Year Budget, PGW's Non-gas tariff revenue requirement, including Other operating revenue, is $578 million (Exhibit HSG-1, line 16). The term "sales" means volumes of natural gas sold to customers and "revenues" means dollars receivable from customers on account of sales, transport service or otherwise.

Q. PLEASE EXPLAIN THE TERM "TARIFF REVENUE REQUIREMENT".

A. As I use the term in my testimony, the "Tariff revenue requirement" is the revenue that needs to be produced under PGW's Tariff in order to recover its total cost of providing service, **before reduction for Customer Responsibility Program ("CRP") Shortfall and for Senior Discounts**. Under the proposed rates, PGW would not collect the full Tariff revenue requirement, because the amounts collected would be reduced by the CRP Shortfall and Senior Discounts.

Q. DID YOU COMPARE THE REVENUE UNDER THE CURRENT TARIFF TO THE REVENUE UNDER THE TARIFF RATES THAT THE COMPANY IS PROPOSING?

A. Yes. Based on the costs and physical quantities in the Test Year Budget, PGW's Test Year non-gas revenue under the current Tariff would be $519.1 million (Exhibit HSG-1, line 3 and Exhibit HSG-6Q, line 43) before deducting CRP Shortfall and Senior Discounts. On a comparable basis PGW's Test Year revenue under the Tariff rates proposed by the Company would be $561.6 million (Exhibit HSG-7C, line 43), an increase of $42.5 million.

Q. PLEASE IDENTIFY THE EXHIBITS[1] THAT YOU ARE SPONSORING.

A. The following exhibits are sponsored by me. They are discussed in detail in Section 3 of my testimony.

Exhibit HSG-1	Summary of Results
Exhibit HSG-1A	Total Class Allocation
Exhibit HSG-1B	Revenue Requirement By Functional Classification
Exhibit HSG-2	Functionalization
Exhibit HSG-3	Classifications
Exhibit HSG-4A through Exhibit HSG-4H	Class Allocations
Exhibit HSG-5A	Allocator Values – Functionalization
Exhibit HSG-5B	Allocator Values – Classification
Exhibit HSG-5C	Allocator Values – Class Allocation
Exhibit HSG-5D	Assignment or Allocator Used for Each Account
Exhibit HSG-6	Development of External Allocator Values
Exhibit HSG-7A	Company's Proposed Revenue Allocation
Exhibit HSG-7B	Development of Company's Proposed Delivery Charges

[1] These exhibits are located in the Cost Service Study which is Volume III of this filing.

Exhibit HSG-7C	Revenue at Company's Proposed Rates
Exhibit HSG-7D	Summary of Company's Proposed Revenue Allocation and Rate Design
Exhibit HSG-8	Gas Supply Costs in Base Rates

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR WORK.

A. I have reached the following results and conclusions based on my work:

1. Based on the costs and physical quantities in the Test Year Budget, the Non-gas Tariff revenue requirement has been assigned among the Rate Classes on a **cost causation** basis as shown on Exhibit HSG-1, line 16.
2. The **increase (decrease)** in Tariff revenue for each Rate Class needed to produce the fully allocated Non-gas Tariff Revenue Requirements is shown on Exhibit HSG-1, line 15.
3. The Company's **proposed** revenue allocation would result in the under and over-recoveries of Non-Gas Tariff Revenue Requirements as shown in Exhibit HSG-7A, lines 37-38.
4. The current (and proposed) monthly Customer Charges are significantly lower than the customer related costs in the Test Year Budget, as shown on Exhibit HSG-1B, line 31.

SECTION II – PGW CLASS COST OF SERVICE STUDY

Q. PLEASE BRIEFLY DESCRIBE THE PURPOSE IN PERFORMING A CLASS COST OF SERVICE STUDY.

A. An unbundled fully allocated CCOSS analyzes all the functional components of the utility's total cost of service and assigns plant investments and operating expenses, including gas supply costs, to determine the costs incurred by the utility in providing products and services to each Rate Class. The CCOSS determines the Revenue Requirement for each Rate Class. The Revenue Requirement for a Rate Class is that portion of the total costs of service incurred by PGW that can be attributed to that Rate Class on a cost-causation basis. An important aspect of a CCOSS is that all of the utility's costs of providing service must be analyzed and allocated among the Rate Classes, so that the utility can establish rates that ensure, subject to assumptions such as sales volumes and customer counts, that it recovers all of its costs.

Q. PLEASE EXPLAIN THE TERM "UNBUNDLED" WITH RESPECT TO THE COSTS OF PROVIDING NATURAL GAS SERVICE.

A. Unbundling is the separation of the utility's cost of service into its various product and service components. The PGW CCOSS follows the unbundling of PGW's rates pursuant to the Commission's Order in Docket M-00021612. This is further discussed in my discussion of the Functionalization step of the CCOSS.

Q. WHAT RATE CLASSES ARE INCLUDED IN THE PGW CCOSS?

A. Each of the following is separately reflect in the PGW COSS, because each has its own usage profile:

- Residential Non-heating
- Residential Heating
- Commercial Non-heating
- Commercial Heating
- Industrial Non-heating
- Industrial Non-heating
- Municipal Non-heating
- Municipal Non-heating
- PHA
- Interruptible Sales

- GTS / IT

The rate classes are the same as in the previous class cost of service studies I conducted for PGW, except I combined the Interruptible Sales classes, because they pay only a customer charge and no volumetric delivery charge and the pricing for delivery service is based on alternative fuels prices.

Each rate class above, except for Interruptible Sales and GTS / IT, includes delivery volumes for firm sales customers and for firm transportation customers. The CCOSS excludes the revenue and costs associated with firm sales, therefore the service provided by PGW to these customers is identical, consisting of firm transportation and delivery service, and the costs incurred by PGW are the same to serve for firm sales customers as firm transportation customers in each rate class.

Q. PLEASE SUMMARIZE THE APPROACH THAT YOU FOLLOWED IN PERFORMING THE PGW CCOSS.

A. The most critical task in performing a CCOSS is establishing relationships between customer requirements, load profiles and usage characteristics on the one hand, and the costs incurred to serve those requirements on the other hand.

PGW designs its gas distribution system to meet three primary objectives:

1. To extend distribution services to all customers;
2. To meet the aggregate peak design day capacity requirements of all customers entitled to receive service on the peak design day, and
3. To deliver volumes of natural gas to those customers either on a sales or transportation service basis.

It is important that the allocation methods used within the CCOSS recognize these ***cost causative*** characteristics of the company's plant investments and operating expenses. The CCOSS should objectively reflect cost causation factors attributable to the utility's customers, their gas usage requirements, and system operations, and to the extent possible, should not be influenced by desired end-results, customer equity, or other rate design considerations.

The CCOSS was performed using the Black & Veatch proprietary Gas Cost of Service Model ("Model"), an EXCEL based spreadsheet computer model. The Model is a tool that facilitates the allocation of common costs, speeds up computations and eases documentation.

The study uses a basic three-step process of cost analysis: 1) *functionalization* of rate base, purchased gas supply costs and expenses among the following functions – supply, storage, transmission, distribution, onsite (including metering and customer accounts) and Universal Service and Energy Conservation Charge ("USEC"); 2) *classification* of functionalized costs into demand, commodity and customer cost categories; and 3) *class allocation* of functionalized, classified costs among the Rate Classes. The Model provides functionalized and classified cost information by service class, develops unbundled Tariff Revenue Requirements by functional classification and in total for each Rate Class, and calculates unit costs by function for demand, commodity and Rate Classifications.

Q. WHY DID YOU USE BUDGETED DATA FOR THE TEST YEAR IN THE PGW CCOSS?

A. The purpose of using budgeted data is to avoid any effect of weather in the CCOSS results and the ensuing rate design. The PGW budget assumes that weather will be normal, and that weather related revenues and costs will be consistent with average weather assumptions. If PGW were to base its cost of service on actual historical data, the data would have to be normalized to remove the effects of weather. It is more reliable to use budget data based on a weather-normal year, than to normalize historical data.

Q. ARE THERE NOTEWORTHY DIFFERENCES IN METHODOLOGY OR APPROACH IN THE CURRENT CCOSS FROM THE PREVIOUS CCOSS YOU PERFORMED FOR PGW?

A. The methodology that I used is the same as that used in performing prior CCOSS for PGW. In a few cases there were changes in the allocators selected for certain accounts, with very small effect on the results of the CCOSS.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION STEP OF A COSS.

A. In the **functionalization** step, costs are separated by the utility's basic service characteristics. The PGW CCOSS follows the functional unbundling of PGW's Tariff pursuant to the Commission's Order in Docket M-00021612, as follows:

- *Supply* function includes the cost of liquefied natural gas ("LNG") liquefaction and vaporization, LNG operating expenses and commodity costs for Interruptible sales customers. In compliance with the Commission's Order in Docket R-00061931 (PGW), the CCOSS **removes** GCR revenues and the costs collected under the GCR clause, in order to present an unbundled study.
- *Storage* function reflects costs incurred to ensure that firm customers' demand can be met on the design day. It includes the costs of storage capacity, storage demand, storage injections and withdrawals and annual demand charges. These costs are included in the unbundled Load Balancing Charge.
- *Transmission* function includes pipeline demand charges.

- *Onsite* function includes the costs of operating activities starting at the meter on the customer's premises and includes metering, billing and accounting and certain customer assistance expenses.
- *USEC* function includes items collected through the USEC Charge, such as CRP Shortfall, Senior Discounts, CAP portion of Uncollectible Accounts Expense, and a portion of the costs of the Customer Assistance Program.
- *Distribution* function includes all other costs, including operating expenses, the amounts of Uncollectible Accounts Expense and Customer Assistance Program not included elsewhere, and costs that are part of PGW's regulated utility function.

The total of supply, storage and transmission functionalized costs applicable to firm supply customers, excluding certain gas production costs, is recovered through the Gas Cost Recovery charge.

Q. PLEASE DESCRIBE THE CLASSIFICATION STEP OF A CCOSS.

A. In the **classification** step, the previously functionalized costs are separated according to the system design or operating characteristics that cause those costs to be incurred. In this step, each cost is determined to be incurred to serve **customers**, to supply the natural gas **commodity** or to meet various capacity **demands** including coincident and non-coincident peaks.

Customer related costs are the costs incurred to attach a customer to the distribution system, to meter gas usage and to maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the particular customer uses any gas. They include capital costs associated with distribution mains, services and meters, and operating costs such as customer service, field service, billing and accounting expenses.

Commodity related costs are those costs that vary with the natural gas throughput sold to, or transported for, customers. These costs include the cost of the commodity, lost and unaccounted for gas, as well as related procurement and supply management costs.

Demand, or **capacity**, related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as measuring and regulating equipment. Contracts for gas supply, transportation (from supply source to City Gate) and storage are also demand related, related to meeting design day demand and the demand throughout the peak season. For PGW the peak season is December through February. Demand-related costs associated with serving the *system design day* are allocated among the Rate Classes based upon contribution to the *system design day* requirements. Demand-related costs associated with managing supply throughout the *peak season* are allocated among the Rate Classes based upon contribution to the *peak season* requirements.

Q. DO ALL EXPENSES FIT NEATLY INTO ONE OF THESE THREE CLASSIFICATIONS?

A. Most costs do fit neatly into one of the three classifications, but it may be necessary to assign some costs among two classifications based upon special external studies or based upon how related costs have been classified through the use of internal classification allocation factors. For example, Account 376, Mains, was classified as both customer and demand related due to their dual function of connecting customers and meeting peak demand.

Q. PLEASE DESCRIBE THE CLASS ALLOCATION STEP OF A CCOSS.

A. In the **class allocation** step, the functionalized, classified costs are allocated among the Rate Classes, based on causal relationships based on the utility's gas system design and operations, its accounting records and its system and customer load data (e.g., annual and peak period gas consumption levels). From the results of those analyses, direct assignments of costs, as well as class allocators, are chosen for each of the plant and expense items.

Q. PLEASE EXPLAIN THE TERM "DIRECT ASSIGNMENT."

A. The term "direct assignment" means identifying plant investments or costs incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation of serving individual customers or groups of customers, and should be used whenever the data are available.

Q. IS A LARGE PORTION OF THE PLANT AND EXPENSES TYPICALLY DIRECTLY ASSIGNED?

A. No, it is not. The nature of utility operations is characterized by common or joint use facilities. In addition, direct assignments require detailed information which may be unavailable or may require a great deal of time to obtain and use. Therefore, to the extent that a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign the remaining costs to the Rate Classes.

Q. PLEASE EXPLAIN HOW ALLOCATORS ARE DERIVED.

A. There are two types of allocation bases, or allocators, used in performing a CCOSS and employed in the Model: external allocators and internal allocators.

External allocators are based on special studies derived from data in the utility's accounting and other records. For example, gas deliveries, the volume of gas consumed by each Rate Class, is an external allocator that is used to allocate some of the gas commodity costs. Other examples of external allocators are number of customers, estimated design day sales and historical bad debt experience. Exhibit HSG -6A shows the external allocators that were developed based on data provided by PGW.

Internal allocators are based on some combination of external allocators, previously directly assigned costs and other internal allocators. For example, the allocators for property insurance costs are based on plant investment amounts assigned to components of the rate base; it is necessary to compute the rate base before property insurance costs can be assigned. Both external and internal allocators are used in each of the functionalization, classification and class allocation steps.

Q. WHAT ARE THE GUIDING PRINCIPLES IN PERFORMING A FULLY ALLOCATED CCOSS?

A. The essential element in performing a CCOSS is the selection of allocators based on causal relationships between customer requirements, load profiles and usage characteristics on the one hand, and the costs incurred by the Company in serving those requirements on the other hand. The primary objectives in selecting allocators are:

1. recognition of **cost causality** as opposed to **value of service**;
2. **stability** of results over time;
3. logical **consistency** and **completeness**; and
4. **ease of implementation.**

Q. WHAT IS THE RATE BASE AND HOW DOES IT AFFECT THE PGW CCOSS?

A. The rate base is the cost, net of accumulated depreciation, of PGW's investment in plant and other assets used to serve customers. In a typical investor-owned utility, the size of the rate base is important because the utility is allowed to earn a return on its investment in rate base. This is not the case for PGW, because PGW's rates are designed to allow it to collect the dollar amount needed to meet its financial requirements. Therefore, PGW's Tariff revenue requirement is not directly affected by the size of the rate base. However the rate base is an important allocator, because PGW, as most utilities, is asset or rate base intensive and its assets drive a great many of PGW's costs. Therefore many costs are functionalized, classified or allocated among Rate Classes in the same ratio as the rate base or a portion of the rate base.

For example, interest expense on long-term debt is functionalized, classified and allocated among Rate Classes using the rate base, because interest expense is incurred to finance the purchase of the assets in the rate base.

Q. WHAT ARE THE MAJOR COMPONENTS OF PGW'S RATE BASE?

A. For purposes of discussing how I functionalized, classified and allocated the rate base in the PGW CCOSS, I will refer to the following groupings of rate base items. After presenting the list, I will describe how I treated each of these major rate base categories:

- Production plant
- Storage plant
- Distribution plant
- General plant
- Depreciation reserve
- Other Rate Base items
- Working capital

Q. WHAT IS THE TOTAL RATE BASE?

A. The total rate base is $1.2 billion, net of accumulated depreciation.

Q. HOW DID YOU FUNCTIONALIZE, CLASSIFY AND ALLOCATE AMONG RATE CLASSES EACH COMPONENT OF RATE BASE?

A. The principal allocators for each component of the rate base are:.

Production plant represents the investment in natural gas production assets which are used to meet design day demand. These assets have been functionalized to Supply, classified to demand, and allocated among Rate Classes based on design day supply requirements.

Storage plant primarily represents the investment in liquefied natural gas ("LNG") facilities which are used to meet design day demand, and to meet demand swings. These assets have been functionalized to Storage, classified to demand, and allocated among Rate Classes based on design day supply requirements.

Distribution plant comprises:

- Mains- Mains have a dual purpose: (1) to attach a customer and enable the customer to receive a minimal level of service, and (2) to provide adequate capacity for the maximum demand level by the customer. The first purpose is customer related and the second is demand related. In compliance with the Commission's Orders in Docket R-00061931 (PGW) and Docket R-00061398 (PPL Gas Utilities Corporation), I used the Average and Excess Demand method to allocate the cost of Mains. This method is recognized as an acceptable method by the American Gas Association Gas Rate Fundamentals, 1987 Edition. In the Average and Excess Demand method, the portion of mains costs equal to the system average load factor is classified as commodity-related and allocated among Rate Classes based on annual deliveries. The balance of mains costs is classified as demand-related and allocated among Rate Classes based on Excess Demand, which is the excess of each class' design demand over its average demand.
- Services- Services connect individual customers to the system. These assets have been functionalized to Distribution, classified as customer related costs, and allocated among Rate Classes based on the estimated total replacement cost for each Rate Class. Total replacement cost of Services for a Rate Class was estimated by multiplying: X) replacement cost of a service line with typical diameter for the Rate Class, by Y) number of customers in the Rate Class.

- <u>Meters and Meter installation</u>- These assets have been functionalized to the Onsite function, classified as customer related costs and allocated among Rate Classes based on the estimated total replacement cost for each Rate Class. Total replacement cost of Meters for a Rate Class was estimated by multiplying X) replacement cost of a meter with typical size for the Rate Class by Y) number of customers in the Rate Class.
- <u>Other Distribution plant</u>- . These assets comprise a) House regulators and House regulator installation, which have been re-functionalized to the Onsite function, classified as customer-related and allocated among residential Rate Classes based on customer counts; b) Compressor station equipment and Measuring and Regulator station equipment, which was functionalized to Distribution, classified as demand-related and allocated among Rate Classes based on design day requirements for mains; c) Land and land rights, Structures and improvements and Other equipment, which were functionalized to Distribution, classified as demand-related and allocated among Rate Classes based on averages for Distribution plant; and d) Industrial Measuring and Regulator station equipment, which was functionalized to Distribution, classified as demand-related and allocated among non-residential Rate Classes based on customer counts.

<u>General plant</u> includes primarily Structures and improvements, Office furniture and equipment, Transportation equipment, Communications equipment and

Tools. These assets, which are used in performing more than one function or are used in Administrative and general activities that support more than one function, were functionalized, classified and allocated among Rate Classes primarily based on direct labor content. Labor was used due to the nature of the assets and reflecting common utility practice.

Depreciation reserve was provided by PGW detailed as to Production plant, Storage plant, Distribution plant and Onsite plant, with Distribution detailed as to Mains, Services and Meters. Each component of Depreciation reserve item was functionalized, classified and allocated among Rate Classes in the same ratio as the related assets.

Working capital represents PGW's need for cash to keep the business running until revenues are collected to pay costs. Each item of working capital was functionalized, classified and allocated among Rate Classes in the same ratio as the activity which caused the item to be incurred.

Q. WHAT ARE THE MAJOR CATEGORIES OF COSTS IN PGW'S COST OF SERVICE?

A. The major categories in PGW's cost of service are:

- Production and supply costs
- Storage costs
- Distribution costs
- Customer accounts, customer service and sales costs
- Administrative and general expenses
- Depreciation expense

- Payroll tax expense
- Interest and Surplus
- Other revenues and expenses

Q. IN DETERMINING HOW YOU WOULD TREAT THESE EXPENSES IN THE CCOSS, WAS THERE ANY OTHER IMPORTANT CATEGORY OF COSTS THAT YOU CONSIDERED?

A. Yes, Labor costs affect most of the cost categories because many costs are assigned based on the direct labor content of other costs. For example, Account 870, Operations Supervision and Engineering, is allocated among Rate Classes based on the direct labor content of distribution and onsite costs. To enable these allocations to be performed, the direct labor content of each cost account was obtained from PGW, and special allocators were developed so that costs could be assigned based on only the direct labor content of accounts.

Q. WHAT COSTS ARE INCLUDED IN PRODUCTION AND SUPPLY AND HOW WERE THESE COSTS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. As noted above the CCOSS **removes** GCR revenues and the costs collected under the GCR clause. The production and supply costs in the CCOSS comprise:

- Commodity costs for Interruptible sales, which were functionalized to Supply, classified as commodity and assigned to Interruptible Sales.
- Natural gas operating expenses, which relate to year-round gas supply, and were functionalized to Supply, classified as commodity and allocated among Rate Classes based on sales to firm supply customers.
- Costs of operating PGW's LNG plants, which are used to meet peak day supply requirements, were functionalized to Storage, classified as demand

and allocated among Rate Classes based on design day supply requirements.

Q. WHAT COSTS ARE INCLUDED IN STORAGE AND HOW WERE THESE COSTS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Storage costs are the costs of operating PGW's LNG facilities. PGW maintains these facilities to meet peak demand, primarily on the design day. Therefore, these costs were functionalized to Storage, classified as demand and allocated among Rate Classes based on design day supply requirements.

Q. WHAT COSTS ARE INCLUDED IN PGW'S DISTRIBUTION COSTS?

A. Distribution costs are the costs of operating and maintaining PGW's City Gate station, mains, services and meters, i.e., the gas delivery system. Some of these costs are functionalized to distribution and some to onsite. Each cost was analyzed to determine whether it was incurred to manage gas supply, maintain equipment or for supervision.

Q. HOW WERE DISTRIBUTION COSTS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Costs relating to <u>managing gas supply</u> were functionalized to Distribution, classified to demand and allocated among Rate Classes based on sales volumes. Costs related to the <u>City Gate station</u> or <u>Measuring and regulating equipment</u> were functionalized to Distribution, classified to commodity and allocated among Rate Classes based on design day usage of the assets.

Costs of <u>operating and maintaining mains, services, meters and house regulators</u> were functionalized, classified and allocated among Rate Classes in proportion to PGW's investments in the respective assets.

Costs of work performed on customer premises were functionalized to Onsite and classified to customer. The portion of these costs related to PGW's parts and labor plan were allocated to the residential classes, consistent with the allocation of parts and labor plan revenue; and the remaining costs were allocated among Rate Classes based on PGW's investment in meters for sales classes.

Other distribution costs were functionalized between Distribution and Onsite in proportion to the functionalization of distribution plant, and classified to customer. The Distribution function portion was allocated among Rate Classes in proportion to plant functionally classified as Distribution customer and the Onsite function portion was allocated in proportion to plant functionally classified as Onsite customer.

Supervision costs were functionalized to Distribution and Onsite in proportion to the functionalization of Distribution plant and were classified and allocated among Rate Classes in proportion to the direct labor content of Distribution function expenses.

Q. HOW WERE CUSTOMER ACCOUNTS COSTS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Customer accounts costs includes meter reading expenses, customer records and collection expenses, related supervision, uncollectible accounts expense and uncollectible accounts- CRP arrearages.

Meter reading expenses and related supervision were functionalized to Onsite, classified to customer and allocated among Rate Classes based on investment in meters and in number of meters. Exhibit HSG-6M shows how the METERREAD allocator was developed.

Customer records and collection expenses and related supervision, which includes telephone service, district offices, bill preparation, collection labor and support, collection processing and other activities, were functionalized to Onsite, classified to customer. For allocation among Rate Classes, the account was analyzed in detail to identify different activities and each activity was allocated using an appropriate basis. For example, telephone services and bill preparation were allocated based on customer counts; collection efforts were allocated based on accounts over 60 days past due. Exhibit HSG-6K shows how the Account903 allocator was developed. Exhibit HSG-6N shows how the Over60 allocator was developed.

Uncollectible accounts expense, or bad debts expense, is presented net of recoveries of amounts previously written off. This item was functionalized to distribution and classified to customer, and allocated among Rate Classes based on the average shares of total write-offs for 2008, as shown on Exhibit HSG-6O.

Uncollectible accounts- CRP arrearages were functionalized to USEC, classified to customer and allocated among Rate Classes based on firm gas sales, consistent with the recovery method for these costs under the USEC charge.

Q. HOW WERE CUSTOMER SERVICE AND INFORMATION COSTS FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Customer service and information costs includes marketing costs, CAP program costs, CRP shortfall and Senior discount.

Marketing costs were functionalized to Onsite classified to customer, then analyzed to determine which customer types were addressed and allocated among Rate Classes using the average number of customers for those classes. Exhibit HSG-6L shows how the Account908 allocator was developed.

CAP program costs, CRP shortfall and Senior discount were functionalized to USEC, classified to customer and allocated among Rate Classes based on firm gas sales, consistent with the recovery method for these costs under the USEC charge.

Q. HOW WERE ADMINISTRATIVE AND GENERAL EXPENSES FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Administrative and general expenses include administrative and general salaries, office supplies and expenses, outside services, injuries and damages, employee benefits, property insurance costs, regulatory commission expenses, miscellaneous general expenses, maintenance of general plant and rents. These costs have been reduced by offsets for capitalized labor costs and for gas used by the utility.

Administrative and general costs, except for items discussed immediately below, are directly related to labor costs and therefore were functionalized, classified and allocated among Rate Classes in the same ratios as direct labor content. These costs include $42.5 million required for PGW to fund Other Post-Employment Benefits ("OPEB") costs.

Property insurance costs were functionalized, classified and allocated among Rate Classes in the same ratio as plant in service.

Regulatory commission expenses were functionalized to Distribution, classified to customer and allocated among Rate Classes in the same ratios as the rate base.

Capitalized labor costs and Gas used by the utility were functionalized, classified and allocated among Rate Classes in the same ratios as the costs which they are reversing.

Q. HOW WAS DEPRECIATION EXPENSE FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Depreciation expense includes depreciation expense on plant in service and costs of removal less capitalized depreciation expense, and was functionalized, classified and allocated among Rate Classes in the same ratios as plant in service.

Q. HOW WAS PAYROLL TAX EXPENSE FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Payroll tax expense was functionalized, classified and allocated among Rate Classes based on direct labor content.

Q. PLEASE DESCRIBE THE INTEREST AND SURPLUS REQUIREMENT INCLUDED IN PGW'S REVENUE REQUIREMENT.

A. Interest expense includes interest on long term debt, amortization of debt discounts, premiums, and loss on reacquired debt, interest on tax-exempt commercial paper and interest on customer deposits. It also includes the AFUDC credit. The surplus is the Test Year budgeted surplus including pro forma adjustments, as shown in Mr. Bogdonavage's testimony.

Q. DO THESE REQUIREMENTS DIFFER FROM A TYPICAL INVESTOR-OWNED UTILITY?

A. Yes, they do. In a typical investor-owned utility, an important component of the revenue requirement is the overall rate of return on rate base the utility is authorized to earn. The return is usually stated as a percent return on rate base; the amount of the return is designed to allow the utility to pay interest on debt and to provide a return on equity. However PGW includes in its Tariff revenue requirement the dollar amount of its interest and surplus requirements, rather than an amount based on its overall cost of capital, including a return to equity investors.

Q. ARE THERE OTHER SIGNIFICANT DIFFERENCES FROM A TYPICAL INVESTOR-OWNED UTILITY?

A. Yes. A typical investor-owned utility is subject to taxation including income tax, gross receipts tax and other taxes. In order for the utility to recover the net amount of cash it needs, the amounts it collects must include amounts to provide for these taxes.

PGW is not subject to an income tax or gross receipts tax and does not have to take them into consideration when computing its revenue requirements.

Q. HOW WERE INTEREST EXPENSE AND AFUDC CREDIT FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Debt Service and Interest expense was functionalized, classified and allocated among Rate Classes in proportion to the rate base.

The Allowance for Funds Used During Construction Credit was functionalized and classified in proportion to plant in service and allocated among Rate Classes in proportion to the rate base.

Q. HOW WAS THE SURPLUS REQUIREMENT FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. In a typical investor-owned utility, the return to equity capital is allocated among Rate Classes in proportion to the rate base. PGW's surplus requirement serves a similar function to the return to equity capital, and therefore was functionalized to

Distribution, classified to customer and allocated among Rate Classes in proportion to the rate base.

Q. PLEASE DESCRIBE PGW'S NON-OPERATING REVENUES AND HOW THEY ARE REFLECTED IN THE COMPUTATION OF THE REVENUE REQUIREMENT.

A. Non-operating revenues includes primarily interest and dividend income from temporary cash investments, parts and labor plan revenue, bill paid turn-ons (i.e., service restoration fees) & dig-ups revenue charged to customers, and capacity release credits. These items are used to reduce the revenue requirement that needs to be collected under the proposed rates.

Q. HOW WERE NON-OPERATING REVENUES FUNCTIONALIZED, CLASSIFIED AND ALLOCATED AMONG RATE CLASSES?

A. Interest and dividend income was functionalized, classified and allocated among Rate Classes in proportion to the rate base, which is the same as interest expense.

Parts and labor plan revenue was functionalized to Onsite, classified to customer and allocated among residential classes.

Bill paid turn-ons & dig-ups revenue was functionalized to Onsite, classified to customer and allocated among Rate Classes based on average number of customers.

Capacity release credits were functionalized to Supply, classified as demand and allocated among Rate Classes in proportion to design day supply requirements, which is related to capacity costs.

Q. HOW WERE PGW'S OPERATING REVENUES AT PRESENT RATES COMPUTED AND ASSIGNED AMONG RATE CLASSES?

A. For the following charges, revenues at present rates were computed by multiplying present rates by forecast billing units, which were available by Rate Class: Base Rate Revenue, GCR Revenue, Interruptible Gas Revenue, USEC Revenue.

Finance charge revenue, determined from PGW's budget, was allocated among the Rate Classes based on an analysis of over-60 day balances.

Miscellaneous service revenue, determined from PGW's budget, was allocated among the Rate Classes in proportion to base rate revenue.

Transport Gas revenue, determined from PGW's budget, was directly assigned to the GTS / IT class.

Gas revenue adjustment, representing unbilled gas revenues, determined from PGW's budget, was allocated among the Rate Classes in proportion to GCR Revenue.

Revenue adjustments, representing reconciling amounts from the prior year, determined from PGW's budget, includes Interruptible Revenue Credit reconciliation, which was allocated in proportion to GCR Revenue, and USEC reconciliation amount, which was allocated in proportion to USEC Revenue.

Q. ARE THERE ANY OTHER COMPONENTS TO THE PGW COSS THAT WARRANT DISCUSSION?

A. No, the above testimony addresses all significant components of the PGW COSS.

SECTION III – RESULTS OF THE PGW CCOSS

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBIT HSG-1.

A. Exhibit HSG-1 compares the revenue at current rates provided by each rate class (line 5) to the revenue requirement allocated on a cost of service basis. The revenue requirement includes operating expenses (lines 8-11) and interest and surplus (line 14).

The increase or decrease needed for each Rate Class to pay its full cost of service, determined on a cost causation basis, including $42.5 million to fund OPEB costs, is shown on line 15. Line 17 shows the percentage increase or decrease in revenue needed for each Rate Class to pay its full cost of service.

Line 21 shows the Return on rate base (before interest and surplus) for each Rate at present rates Class, and line 22 shows the relative returns.

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBIT HSG-1A.

A. Exhibit HSG-1A summarizes the results of the class allocations on Exhibits HSG 4A through 4H, by FERC account detail. The exhibit shows the allocation of each item of rate base (lines 1-74), operating expenses (lines 75-170), depreciation expense (lines 171-175) and taxes (lines 176-178). Total operating expenses are on line 179.

The exhibit then shows operating revenues at present rates (lines 181-193), other operating revenues (lines 194-197), total operating revenue (line 198) and non-operating revenue (lines 199-203). Total revenue is on line 204 and income before interest and surplus is on line 206. Interest and surplus requirements are on lines 208-214. A comparison of revenue at current rates to the total revenue requirement on a cost of service basis is on line 215. A negative number indicates that the Rate Class' current revenue produces less than its full cost of service revenue requirement, and a positive number indicates that the Rate Class' current revenue produces more than its full cost of service revenue requirement.

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBIT HSG-1B.

A. Exhibit HSG-1B shows how each item of the revenue requirement has been allocated among the functions: supply, storage, transmission, distribution, onsite and USEC. The exhibit shows the allocator for each item, and the result of the allocation. The line captions are the same as in Exhibit HSG-1A.

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBIT HSG-2.

A. Exhibit HSG-2 shows how each item of the Supply function revenue requirement was classified as demand or commodity, and of the Distribution function as demand or customer. The exhibit shows the allocator selected for each item, and the result of the allocation. The line captions are the same as in Exhibit HSG-1A. Items functionalized to Storage as 100% demand, and to Onsite and USEC as 100% customer, therefore these functions are not shown on the exhibit.

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBITS HSG-4A THROUGH 4H.

A. Exhibits HSG-4A through 4H show how each item of each functional classification of the revenue requirement was allocated among the rate classes. Each exhibit show the allocator selected for each item, and the result of the allocation. The line captions are the same as in Exhibit HSG-1A.. The information is shown on the following pages:

Exhibit HSG-4A	Supply Demand class allocation
Exhibit HSG-4B	Supply Commodity class allocation
Exhibit HSG-4C	Storage Demand class allocation

Exhibit HSG-4D	Distribution Demand class allocation
Exhibit HSG-4E	Distribution Commodity class allocation
Exhibit HSG-4F	Distribution Customer class allocation
Exhibit HSG-4G	Onsite Customer class allocation
Exhibit HSG-4H	USEC Customer class allocation

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBITS HSG-5A THROUGH HSG-5D.

A. Exhibit HSG-5A shows the assignment and allocator values for functional assignment and allocation of the revenue requirement. Exhibit HSG-5B shows the assignment and allocator values for classification of the functionalized revenue requirement components. Exhibit HSG-5C shows the assignment and allocator values for allocation of functionally classified components of the revenue requirement among the Rate Classes. External allocators and internal allocators are identified by "EXT" and "INT, respectively, next to their names on Exhibits HSG-5A through 5C. External and internal allocators were discussed above.

Exhibit HSG-5D shows the assignment or allocator used for each account, at each step: functionalization; classification; and allocation among Rate Classes.

Q. PLEASE EXPLAIN THE CUSTOMER RELATED COSTS IN THE PGW COSS.

A. As previously described, customer related costs are the costs incurred to attach a customer to the distribution system, to meter gas usage and to maintain the customer's account. The total of all customer costs for PGW is a function of the number of customers served. Customer costs continue to be incurred whether or not a particular customer uses any gas. They include capital costs associated with distribution mains, services and meters, and operating costs such as customer service and accounting expenses. Distribution customer costs by Rate Class for the Test Year are shown on Exhibit HSG-1B, line 12, and on a unit basis, on line 27; Onsite customer costs are on line 15, and on a unit basis, on line 28.

Q. DID YOU COMPARE THE MONTHLY CUSTOMER CHARGES BEING PROPOSED BY PGW TO THE CUSTOMER RELATED COSTS IN THE PGW COSS?

A. Yes. For every Rate Class, the proposed monthly Customer Charge (which is the same as the current monthly Customer Charge for that rate class) is lower than the customer related costs on a per customer-month basis in the PGW COSS for the Test Year.

Q. PLEASE DESCRIBE THE INFORMATION ON EXHIBIT HSG-6.

A. Exhibit HSG-6 presents the development of each of the main external allocators. These are described below. Except where noted, all data relate to the Test Year.

Exhibit HSG-6A- Allocators Values. Lists the allocators that are developed in Exhibit HSG-6

Exhibit HSG-6B- Design Day-Supply: Design Day sendout for each firm sales class as provided by PGW's Gas Model.

Exhibit HSG-6C- Design Day-Mains: Design Day demand for each rate class, computed using Base and Thermal method for non-sales classes; primarily used to allocate demand component of mains.

Exhibit HSG-6D- Sendout: Monthly delivery volumes for each rate class

Exhibit HSG-6E Thruput Allocator: Monthly throughput volumes for each rate class; represents volumes on mains.

Exhibit HSG-6F GTS Allocator: Annual delivery volumes and revenues for GTS / IT rate class, with details for each subclass.

Exhibit HSG-6G Winter3 Allocator- Monthly billed sales volumes for each firm sales rate class during the December-February.

Exhibit HSG-6H- Cust_Avg Allocator- Monthly number of customers for each rate class.

Exhibit HSG-6I- Meter_Invest Allocator- Investment in meters for each rate class at current replacement cost for each meter type.

Exhibit HSG-6J Service_Invest Allocator- Investment in services for each rate class at current replacement cost for each service line.

Exhibit HSG-6K- Account903 Allocator- Allocates each activity in Customer Records and Collection, Account 903, using an appropriate external allocator. Rows 1-11 list each activity, the activity cost in the Test Year budget, and the allocator assigned to it. Rows 19-33 summarize costs by allocator (e.g., costs for all activities allocated using Cust_Avg allocator are summed) and show the amount allocated to each rate class. Allocator values are on row 25 and row 33.

Exhibit HSG-6L- Account908 Allocator- Allocates each activity in Customer Services and Informational Expenses, Account 908, using an appropriate external allocator. Rows 1-8 list each activity, the activity cost in the Test Year budget, and the allocator assigned to it. Rows 13-23 summarize costs by allocator and show the amount allocated to each rate class. Allocator values are on row 17 and row 23.

Exhibit HSG-6M- METERREAD Allocator- Allocates each activity in Meter Reading, Account 902, using an appropriate external allocator. Rows 1-3 list each activity, the activity cost in the Test Year budget, and the allocator assigned to it. Rows 7-16 summarize costs by allocator and show the amount allocated to each rate class. Allocator values are on row 10 and row 15.

Exhibit HSG-6N- Account Agings- Computes allocator values for the OVER60-D allocator. The columns 'Current', '30 days', '60 days' and '90 days and up' show the values in accounts receivable for each rate class at June 30, 2009.

Exhibit HSG-6O- Write-Offs- Computes allocator values for the WRITE-OFF allocator. Write-off amounts for each rate class are shown for fiscal years 2006-2008, and the percentage of the total represented by each rate class is computed for each year. The column 'WRITE_OFF Allocator' takes the average of the percentages; these are the allocator values.

Exhibit HSG-6P- GTS-DIR-MAINS, GTS-DIR-EXP, GTS-DIR-ACCDEP- Develops direct assignment values for mains based on the mains constructed for specific customers. The information and methodology are consistent with that used in PGW's 2002 and 2006 base rate cases.

Exhibit HSG-6Q- Test Year Tariff Revenue at Current Rates- Proof of revenue at current rates.

SECTION IV – COMPANY'S PROPOSED REVENUE ALLOCATION

Q. WHAT IS THE TOPIC OF THIS SECTION 4 OF YOUR TESTIMONY?

A. In this section I describe the computations that I performed based on the Company's specifications for revenue allocation and proposed rates. The purpose of these computations was to allocate the Company's Tariff revenue requirement among the Rate Classes, and to compute the Company's proposed distribution charge rates that would produce the indicated revenue.

Q. PLEASE DESCRIBE THE COMPANY'S APPROACH TO REVENUE ALLOCATION AND RATE DESIGN.

A. First, the Company's proposed revenue allocation was determined by allocating the Tariff revenue requirement among the Rate Classes based on the Company's specifications for rates of return and other parameters. Then, the Rate Class revenue allocations were used to develop the Company's proposed distribution rates, with volumetric delivery charges continuing to be the same within each of the following groups, including in each case heating and non-heating, and firm sales and firm transportation: Residential; Commercial; Industrial; Municipal. Monthly customer charges are also the same within each such group.

Q. HOW DID YOU COMPUTE RATE OF RETURN?

A. For PGW, rate of return was computed as Income before Interest and Surplus divided Rate Base.

Q. PLEASE DISCUSS THE COMPANY'S APPROACH TO REVENUE ALLOCATION.

A. The Company specified the following approach for allocating the Tariff revenue requirement among the Rate Classes:

1. The rate of return on rate base for each class should be the same as or closer to the requested system average rate of return (9.5%), than projected in PGW's compliance filing in Docket R-00061931 (2006).
2. No changes were made to the GTS / IT, because at current rates this class will generate the requested system average return (9.5%).
3. No changes for Interruptible sales rate. Margins from Interruptible sales rate classes are credited to the GCR.

Q. DID YOU PREPARE A SCHEDULE THAT SHOWS THE COMPANY'S PROPOSED REVENUE ALLOCATION?

A. Yes, the Company's proposed revenue allocation is present Exhibit HSG-7A:

Line 15 shows the return on rate base at current rates and line 16 shows the relative return at current rates, with heating and non-heating classes combined for Residential, Commercial, Industrial and Municipal.

Line 21 shows the Company's proposed increase (decrease) for each rate class and line 23 shows the resulting revenue excluding gas costs and other revenue (e.g. forfeited discounts, service revenue) and before senior discounts and CRP.

Line 37 shows the return on rate base at proposed rates and line 38 shows the relative return, with heating and non-heating classes combined as above.

Q. PLEASE DISCUSS THE COMPANY'S APPROACH TO RATE DESIGN.

A. The Company specified the following approach for developing proposed rates:

1. No changes to monthly fixed Customer charges.
2. Volumetric delivery charges are the same within each of the following groups, including in each case heating and non-heating, and firm sales and firm transportation: Residential; Commercial; Industrial; Municipal. Monthly customer charges are also the same within each such group.
3. Separate rates are established for Philadelphia Housing Authority Rate 8 and for Philadelphia Housing Authority General Service

The computations of delivery charges presented on Exhibit HSG-7B.

Q. DID YOU PREPARE A PROOF OF REVENUE FOR THE PROPOSED RATES?

A. Yes, Exhibit HSG-7C presents a proof of revenue for the Company's proposed rates. The proof of revenue shows the proposed rates produce an increase of $42.5 million over revenue at present rates, before revenue lost due to senior discounts and CRP programs.

Q. DID YOU PREPARE A SCHEDULE THAT SUMMARIZES THE RESULTS OF THE COMPANY'S PROPOSED REVENUE ALLOCATION AND RATE DESIGN?

A. Yes, Exhibit HSG-7D summarizes the results for the firm sales and firm transportation classes.

SECTION V – GAS SUPPLY-RELATED COSTS IN BASE RATES

Q. PLEASE DISCUSS THE COMMITMENT THAT PGW MADE REGARDING PREPARING SCHEDULES TO DEPICT GAS SUPPLY-RELATED COSTS.

A. As outlined in the testimony of PGW witness Kenneth Dybalski (PGW St. 5), the Company agreed to provide schedules depicting gas supply-related costs included in base rates and the related impact of those costs on base rates. Also outlined in Mr. Dybalski's testimony is a similar requirement set forth by the Commission in an Order issued in the SEARCH Proceeding. For reasons discussed in Mr. Dybalski's testimony, PGW directed me to calculate the impact on base rates if commodity-related bad debt expense, commodity-related PUC assessment and the entire PUC assessment were removed from base rates.

Q. HAVE YOU PREPARED A SCHEDULE TO PROVIDE THIS INFORMATION?

A. Yes, I prepared Exhibit HSG-8, which shows commodity-related uncollectibles (i.e. bad debt expense) per mcf by rate class (line 18), the commodity-related PUC assessment per mcf by rate class (line 30) and the entire PUC assessment per mcf by rate class (line 25).

Q. DOES THIS CONCLUDE YOUR TESTIMONY TODAY?

A. Yes.

HOWARD S. GORMAN
Principal Consultant
Black & Veatch Corporation

Mr. Gorman has more than 15 years of experience in the energy industry, and more than 25 years of professional experience in accounting, finance and rate and regulatory matters. Mr. Gorman specializes in the development of revenue requirements, accounting systems, fully allocated and unbundling cost of service studies, rate design, financial modeling, forecasting and analysis, and competitive practices. He is a chief developer of Rudden's proprietary Electric and Gas Cost of Service Models.

Mr. Gorman has testified on matters pertaining to revenue requirements, cost of service, cost allocations and related matters. he has testified before the Massachusetts Department of Public Utilities, New Jersey Board of Public Utilities, New York State Public Service Commission, Ontario Energy Board, Pennsylvania Public Utility Commission, Philadelphia Gas Commission and Rhode Island Public utilities Commission.

Mr. Gorman assisted Philadelphia Gas Works in its base rate cases in 2001, 2002 AND 2006, and in its Restructuring filing. In these filings, Mr. Gorman prepared fully allocated / unbundled cost of service studies, submitted pre-filed testimony, rebuttal testimony and oral testimony to the, and assisted in preparing legal briefs and case management.

Mr. Gorman's other rate and regulatory clients have included Baltimore Gas & Electric, Citizens' Electric Company of Lewisburg, PA, Duquesne Light Company, Freeport Electric, Hydro One Networks, KeySpan Energy, Massachusetts Electric Company and Nantucket Electric Company, Midwest Energy, Narragansett Electric Company, Niagara Mohawk Power Company, PECO Energy Company, Valley Energy, Inc., Village of Rockville Centre, Wellsboro Electric Company, as well as American Transmission Company, Midwest Independent System Operator, New York Independent System Operator and PJM Interconnection, LLC.

PROFESSIONAL EMPLOYMENT

1997 - Present	Black & Veatch Corporation (originally joined R.J. Rudden Associates) Principal Consultant	
1995 - 1997	Independent Consultant	
1987 - 1995	Trigen Energy Corporation	
	1987-1993	Corporate Controller; Trigen was formed in 1987
	1993-1995	Treasurer; Trigen had IPO with NYSE listing in 1994
1982 - 1987	Coleco Industries, Inc. Director, Treasury	
1976 - 1979	Touche Ross & Co. Staff Accountant	

EDUCATION

New York University, B.S., Accounting, 1976
Harvard Business School, MBA, 1981

TAB

9

PGW Statement No. 9

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PREPARED DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

ON BEHALF OF

PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

DECEMBER 2009

Q. PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A. My name is Frank J. Hanley and I am a Principal and Director of AUS Consultants. My business address is 155 Gaither Drive, Suite A, Mount Laurel, New Jersey 08054.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have testified as an expert witness on cost of capital and related financial issues before 33 state public utility commissions including the Pennsylvania Public Utility Commission, the District of Columbia Public Service Commission, the Public Services Commission of the Territory of the U.S. Virgin Islands, and the Federal Energy Regulatory Commission. I have also testified before local and county regulatory bodies, an arbitration panel, a U.S. Bankruptcy Court, the U.S. Tax Court and a state district court. I have appeared on behalf of investor-owned companies, municipalities, and state public utility commissions. I currently provide advisory consulting services to the Regulatory Commission of Alaska. The details of the foregoing as well as my educational background, are shown in Appendix A supplementing this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose is to provide evidence that will demonstrate that the rate increase granted to Philadelphia Gas Works (PGW) in December 2008 should be maintained and that the additional increase requested in this docket, which is designed solely to fund PGW's OPEB liability, should be granted. I review a number of ratios based upon cash flow and other financial ratios including debt-equity ratios for PGW and compare them for reasonableness against those actually experienced by proxy groups of municipal gas systems, Pennsylvania and other publicly-traded, investor-owned, natural gas distribution utilities. My analyses will show that PGW's key financial indicators need to improve over those of the recent past in order to strengthen its financial position and raise its bond rating from the bottom of investment grade. PGW Witness Barbara C. Bisgaier in her testimony explains the difficulty associated with raising debt capital with bonds rated at the bottom of investment grade, a rating that makes raising capital extraordinarily difficult at times and always much more costly than for those competitors for capital that have higher bond ratings. I will demonstrate, based upon the various comparative financial ratios analyzed that, if PGW's existing rates are not reduced and the additional increase to be used solely to fund the OPEB liability is approved, PGW should be able over time to earn an upgrading of its bonds from its current bottom of investment grade rating.

Q. WHAT DATA DID YOU ANALYZE IN ORDER TO FORMULATE YOUR CONCLUSION?

A. I reviewed historical financial data for PGW for the five fiscal years ended 2008 and the pro forma financial statements submitted in this docket, specifically the expected results for the fiscal year ending August 31, 2010 at present rates, that is reflecting the rates authorized on an extraordinary/emergency basis in December 2008, as well as the adjustments to reflect the additional increase requested in this docket which will be placed in trust as such funds will be used exclusively to fund its OPEB liability. I then selected a proxy group of other large municipal gas systems as well as two groups of investor-owned gas distribution companies. I then measured PGW's financial benchmark ratios against those of the proxy groups in order to determine whether PGW's ratios are reasonable and justify making the existing and proposed rate levels permanent.

Based upon available information, as will be described *infra*, I reviewed various financial statistics for the five years ending 2008 for the next six largest municipal gas systems after PGW, which is the largest municipal gas system in the United States.

Because PGW is subject to rate regulation by this Commission, I also reviewed various financial statistics of a proxy group of seven Pennsylvania investor-owned gas distribution companies for the five years ending 2008.

In order to also give my analysis of investor-owned gas distribution companies a more national flavor, I reviewed various financial and operating statistics for the same five-year period for a group of seven publicly-traded gas distribution companies which are reported by *Value Line Investment Survey* (*Value Line*).

Q. HAVE YOU PREPARED AN EXHIBIT WHICH SETS FORTH THE RESULTS OF YOUR ANALYSES?

A. Yes. It has been marked for identification as Exhibit FJH-1 and it consists of six schedules. All references to schedules hereafter are to those in Exhibit FJH-1.

Q. PLEASE DESCRIBE SCHEDULE 1.

A. Schedule 1 contains five-year historical financial data and ratios for PGW by year for the five fiscal years ending August 31, 2004 through 2008. Also shown are the five-year average of the various ratios developed and the range of each ratio. There are eight ratios that I believe are relevant for comparative purposes. They are:

1. Operating Margin
2. Operating Ratio
3. Pre-Tax Earned Return on Total Capital
4. Days Cash
5. Internally Generated Funds
6. Total Debt/Total Capital
7. Total Equity/Total Capital
8. Debt Service Coverage

In the case of PGW, there is one additional level of debt service coverage shown on Schedule 1 which is not applicable to other municipal gas systems. It is a level of fixed charge coverage which assumes payment is required of the $18 million annual fee due to the City of Philadelphia (City). In other words, the basic fixed charge coverage reflects the continued abeyance of such payment to the City. The latter fixed charge coverage includes in the debt service the $18 million fee to the City which the City could require to be paid.

Q. PLEASE DESCRIBE THE SIGNIFICANCE OF THE FINANCIAL RATIOS WHICH YOU UTILIZE IN YOUR ANALYSES.

A. Operating Margin is a ratio which is an indicator of the level of profitability. It relates net operating income plus all taxes (where applicable), except payroll taxes, to total operating revenue. The higher this percentage, the better the indicated level of operating profit.

Operating Ratio is also an indicator of the level of profitability. It is basically a measure of non-cash operating expenses relative to total operating revenues.

Pre-Tax Earned Return on Total Capital is also a measure of profitability. It is a ratio of the level of pre-tax operating income relative to total capitalization. Unlike tax-paying investor-owned utilities, municipal utilities are not subject to taxes other than those which are payroll-related.

Days Cash is an important indicator for municipal utilities which is utilized by the bond rating agencies. It indicates the number of days of unrestricted cash and equivalent investments available to pay operating expenses net of depreciation. This ratio is not utilized by the rating agencies for investor-owned utilities. Days of liquidity is also used by rating agencies for municipal utilities. It represents unrestricted cash plus available lines of credit and unutilized commercial paper capacity related to operating expenses less depreciation. The information necessary to compute this ratio was not available for the other municipal gas systems analyzed. Consequently, it is not included in my comparative analyses.

Internally Generated Funds is an indicator of profitability. It also provides an indication of the level of cash which will need to be funded externally in order to complete necessary construction. It is the ratio of net income plus non-payroll related taxes (where applicable) and non-cash expenses divided by total operating revenues.

Total Debt/Total Capital is the ratio of both long- and short-term debt relative to total capitalization, which is the sum of total debt plus total equity. This is a ratio of the degree of financial leverage employed. To a large extent, this ratio is an indicator of bond rating.

Total Equity/Total Capital is the ratio of total equity capital to total capitalization. Generally speaking, the higher the equity ratio, the better likelihood for a higher bond rating and vice versa.

Debt Service Coverage is the ratio of funds available for debt service (operating income plus depreciation and amortization plus interest income) divided by total annual debt service.

Q. PLEASE EXPLAIN THE BASIS OF SELECTION OF YOUR PROXY GROUP OF MUNICIPAL GAS SYSTEMS.

A. My goal was to select a group of municipal gas systems that were most comparable to PGW. Of course, selecting a group of comparable companies does not make them identical. As noted *supra*, PGW is the largest municipally-owned gas system in the United States. PGW has more than 500,000 customers. I deemed it appropriate to select, for comparative purposes, municipal gas systems with more than 125,000 customers. Based upon a November 23, 2009 ranking of the top 100 municipal gas systems by the American Public Gas Association, there were six other gas systems that had more than 125,000 customers. I believe that a group of the next six largest municipal gas systems represents a reasonable proxy for comparative purposes with PGW. Their information is set forth in Schedule 2.

Q. PLEASE DESCRIBE SCHEDULE 2.

A. Schedule 2 consists of 9 pages. Page 1 contains a summary of the results of my analysis. Pages 2 through 7 contain the information for each municipal gas system. Page 8 contains the basis of selection and the identity of the six municipal gas systems selected. For convenience purposes, their identities are listed *infra*:

Citizens Gas & Coke Utility (Indianapolis, IN)
Colorado Springs Utilities (Colorado Springs, CO)
CPS Energy (San Antonio, TX)
Long Beach Gas and Oil (Long Beach, CA)
Memphis Light, Gas & Water (Memphis, TN)
Metropolitan Utilities District (Omaha, NE)

Page 9 contains the first sheet of the American Public Gas Association's listing of the top 100 municipal gas systems as of November 23, 2009. As can be seen on page 9, those six municipal utilities represent ranking order 2 through 7 based on size. The next largest municipal gas systems after PGW are Memphis Light, Gas & Water with 319,983 customers and CPS Energy with 319,125 customers, while the smallest of the six is Long Beach Gas and Oil with 148,568 customers.

Q. PLEASE EXPLAIN WHY AT PAGES 3 AND 4 OF SCHEDULE 2, NO DATA FOR INTERNALLY-GENERATED FUNDS ARE SHOWN FOR COLORADO SPRINGS UTILITIES AND CPS ENERGY, RESPECTIVELY.

A. Annual reports were not available for those gas systems. All of the information and related ratios shown were derived from Fitch Ratings Reports for those systems as of August 29 and May 20, 2009, respectively. Fitch did not provide this information and thus it is not available. Consequently, the internally-generated funds ratios shown on the summary page 1 of Schedule 2 are based upon the remaining four systems. All of the other ratios are, of course, based upon all six systems.

Q. PLEASE DESCRIBE THE AVERAGE RESULTS AND RANGES FOR THE PROXY GROUP OF SIX MUNICIPAL GAS SYSTEMS AS SUMMARIZED ON SCHEDULE 2, PAGE 1 OF 9.

A. As shown, the average operating margin was 12.48% with the range being between 11.17% and 13.41%. The average operating ratio was 77.24% with a range between 76.64% and 77.99%. The average pre-tax earned return on total capital was 4.89% with a range between 3.70% and 6.76%. The average days cash were 131.13, while the range was between 91.74 and 145.90 days. The average percentage of internally generated funds was 11.93% with a range between 10.24% and 12.75%. The average total debt to total capital ratio was 54.28% with a range between 48.13% and 73.84%. The average total equity to total capital ratio was 45.72% with a range between 26.16% and 51.87%. The average debt service coverage was 10.06 times with a range between 9.02 and 11.12 times.

Q. HAVE YOU COMPARED PGW'S BOND RATINGS WITH THOSE OF THE PROXY GROUP OF SIX MUNICIPAL GAS SYSTEMS?

A. Yes, I have. That information is shown in Schedule 3. The ratings are shown on page 1, while the numerical legend for calculating group average bond ratings is shown on page 2.

As can be seen on page 1, PGW's bond rating by Moody's is Baa2, while that of Standard & Poor's (S&P) is BBB-, the bottom of investment grade ratings. Fitch does not rate PGW. Also shown on page 1 of Schedule 3 are the bond ratings for each of the six proxy municipal gas systems. Three of those systems are rated by Moody's and the average of those three is A1. Four of those six systems are rated by S&P and the average rating is AA-. Three of the six systems are rated by Fitch and the average rating is AA. The average bond rating for the proxy group of six municipal gas systems is AA-. In other words, because of their vastly superior ratios evaluated by the rating agencies, vis-à-vis PGW's ratios, their average bond rating is AA- which is six rating gradations higher than PGW's bottom of investment grade rating of BBB-.

Q. PREVIOUSLY, YOU INDICATED THAT YOU ALSO REVIEWED RELEVANT FINANCIAL RATIOS BASED UPON A PROXY GROUP OF PENNSYLVANIA INVESTOR-OWNED GAS DISTRIBUTION COMPANIES. PLEASE EXPLAIN WHY YOU REVIEWED DATA FOR SUCH A GROUP

AND THE BASIS FOR SELECTION OF THE COMPANIES IN THAT GROUP.

A. I believe it is essential to also review investor-owned gas distribution utilities that have operations in Pennsylvania because PGW is subject to the jurisdiction of this Commission as are the gas distribution companies selected. I reviewed from the Commission's website all of the natural gas distribution companies subject to Commission jurisdiction. I eliminated as feasible proxies all of those companies which had less than $40 million in revenues in the year 2008 because they would be entirely too small for any valid comparison to PGW. Also, the companies selected had to have available from the Commission website their annual reports to the Commission for the years 2004 through 2008. Seven companies met the criteria. The results of my analysis of such companies are set forth in Schedule 4.

Q. PLEASE EXPLAIN SCHEDULE 4.

A. Schedule 4 consists of nine pages and contains the results of my analyses of the seven companies selected. Page 1 contains a summary of the results. Pages 2 through 8 contain the results by year for each of the companies which met the selection criteria. Page 9 contains the selection criteria and the identity of each of the companies selected. For convenience, their identities are listed *infra*.

Columbia Gas of Pennsylvania
Dominion Peoples
Equitable Gas Company
National Fuel Gas Distribution Corporation
Exelon Corporation (PECO Gas)

T.W. Phillips Gas & Oil Company
UGI Utilities, Inc. (Gas)

Two of the ratios that have significant relevance for municipal utilities are days cash and debt service coverage. Those ratios have no significance for investor-owned utilities as they are not utilized by the bond rating agencies for investor-owned utilities. This is ascertained readily by reference to bond rating criteria and the financial benchmarks utilized by the major rating agencies in rating investor-owned entities. Consequently, as shown on page 1 of Schedule 4 are six ratios which are meaningful for comparative purposes with PGW and the proxy group of six municipal gas systems.

The operating margin averaged 10.89% for the five-year period ending 2008 and ranged between 9.06% and 13.59%. The five-year average operating ratio was 85.26% and ranged between 82.26% and 86.78%. The pre-tax earned return on total capital averaged 10.43% and ranged between 7.76% and 13.15%. Internally generated funds averaged 29.74% and ranged between 19.51% and 38.38%. Total debt to total capital averaged 55.30% and ranged between 52.03% and 57.26%. Total equity to total capital averaged 44.70% and ranged between 42.74% and 47.97%.

Q. WHY DID YOU ALSO SELECT A PROXY GROUP OF INVESTOR-OWNED GAS DISTRIBUTION COMPANIES THAT ARE COVERED BY *VALUE LINE*?

A. I believe that it is also useful to obtain pertinent statistics for a group of investor-owned gas distribution companies that is considered by investors to be a proxy for the investor-owned natural gas distribution industry. *Value Line* is a nationally-respected, independent, investment advisory service. *Value Line* is relatively inexpensive and has more than 100,000 subscribers. In addition, it is available in the business reference section of most libraries. It is, therefore, investor-influencing. All of the companies selected are included in *Value Line*'s Natural Gas (Utility) Group in its Standard Edition.

All of the companies included in the *Value Line* Natural Gas (Utility) Group have common stocks which are actively traded and are engaged, to some extent, in activities other than the distribution of natural gas. Consequently, I chose to utilize additional selection criteria in order to ascertain that the companies culled from the *Value Line* Group are financially healthy and significantly representative of natural gas distribution operations. Accordingly, I made sure that each company selected had *Value Line*: five-year growth rates for earnings per share; positive five-year growth rate projections for dividends per share; and a beta. Also, I made sure that none had not cut or omitted their common stock dividends during the five years ending 2008 or up to the time of the preparation of this testimony, and derived 60% or more of their total net operating income and assets from regulated gas operations. Finally, I made sure that they had not publicly announced their involvement in any merger or acquisition activity. Seven companies met those criteria and collectively represent a barometer of financially healthy investor-owned gas distribution companies. Their identities are listed *infra.*

AGL Resources, Inc.
Atmos Energy Corporation
The Laclede Group, Inc.
Northwest Natural Gas Company
Piedmont Natural Gas Company, Inc.
Southwest Gas Corporation
WGL Holdings, Inc.

All of the information related to the selected proxy group of seven *Value Line* natural gas distribution companies is presented in Schedule 5.

Q. PLEASE EXPLAIN SCHEDULE 5.

A. Schedule 5 consists of 9 pages. Page 1 contains a summary of the results of the data analyzed for the period 2004 through 2008. Pages 2 through 8 of Schedule 5 contain information for each company, while page 9 contains the selection criteria described *supra* and the identity of the individual companies as well as the source of information for those companies.

Page 1 shows the five-year average for the six ratios which are relevant for comparative purposes to PGW and the proxy group of six municipal gas companies, as well as the proxy group of seven investor-owned gas distribution utilities subject to regulation by this Commission. Also, the ranges of the statistics are shown.

Q. PLEASE SUMMARIZE THE RESULTS OF THE SIX RATIOS WHICH ARE RELEVANT TO INVESTOR-OWNED GAS DISTRIBUTION UTILITIES.

A. As discussed *supra*, those ratios are summarized on page 1 of Schedule 5. The five-year average operating margin was 12.43% and ranged between 12.09% and 13.14%. The five-year average operating ratio was 83.07% and ranged between 81.81% and 83.86%. The five-year average pre-tax earned return on total capital was 13.23% and ranged between 12.22% and 13.73%. The five-year average internally-generated funds was 14.02% and ranged between 13.28% and 15.22%. The five-year average total debt to total capital was 55.44% and ranged between 53.64% and 56.81%. The five-year average total equity to total capital was 44.56% and ranged between 43.19% and 46.36%.

Q. PLEASE EXPLAIN SCHEDULE 6.

A. There are six columns on Schedule 6. Column 1 contains the five-year historic average ratios for PGW for the period 2004 through 2008 derived from Schedule 1. Column 2 shows the ratios derived from PGW-provided information contained in this rate filing which represents the budget for the fiscal year ended August 31, 2010 and which reflects the rates authorized in December 2008. Column 3 contains information, and related ratios which are meaningful, assuming the additional increase requested in this docket in order to fund PGW's OPEB liability is granted. The column is entitled, "Adjusted Budget 2009-2010" which reflects the full impact of the current rates authorized in December 2008 as well as the additional increase requested in this docket in order to fund PGW's OPEB liability. Only the meaningful statistics are shown in Column 3, that is those that are not impacted by the fact that the dollars to fund the OPEB liability provide no additional wherewithal for PGW to improve operating margin, operating ratio, pre-tax earned return on total capital, or internally-generated funds because the entire amount of the additional increase requested in this rate filing will be placed in trust in order to fund PGW's OPEB liability.

In Column 4 I have shown the five-year average ratios for the proxy group of the six next largest municipal gas systems which were developed in Schedule 2 and summarized on page 1 thereof.

In Column 5 I show the five-year average ratios which are relevant to the seven Pennsylvania natural gas distribution companies. As discussed *supra*, days cash and debt service coverage are ratios which are not relevant to investor-owned utilities.

In Column 6 I have shown the five-year average ratios for the proxy group of seven *Value Line* natural gas distribution companies. Only the same six ratios which are relevant to investor-owned utilities are shown for the reasons discussed *supra*. They are derived from the data in Schedule 5 and summarized on page 1 thereof.

Q. WHAT CONCLUSIONS DO YOU DRAW BASED UPON YOUR ANALYSES WHICH ARE SUMMARIZED ON SCHEDULE 6?

A. I conclude, based upon the financial information and ratios summarized on Schedule 6, that PGW's increase which was granted in December 2008 should be made permanent and, in order to avoid significant erosion of PGW's financial position because of the obligation to fund its OPEB liability, the additional increase requested in this rate filing in order to fund that liability should be granted.

Comparison of the five-year average historical results ending 2008 for PGW as shown in Column 1 of Schedule 6 against the five-year averages for the three proxies, namely, the six municipal gas systems, the seven Pennsylvania natural gas distribution companies, and the seven *Value Line* natural gas distribution companies make it apparent that PGW's historical ratios have been grossly substandard. It is seen that PGW's average operating margin of 7.21% was substantially below the 12.48% for the six municipal gas systems as well as the 10.89% and 12.43% for the two proxy groups of investor-owned gas distribution companies, respectively. Similarly, PGW's five-year historical average operating ratio of 88.19% was unfavorably higher than the 77.24% for the six municipal gas systems and the 85.26% and 83.07% for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups. While the pre-tax earned return on total capital of 4.45% was somewhat below the 4.89% achieved for the six municipal gas systems, it was substantially below the 10.43% and 13.23% for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups.

As indicated *supra*, days cash is not a meaningful comparison between a municipal gas system and an investor-owned gas distribution company. However, note that PGW's five-year historic average of 12.07 days was grossly below the 131.13 days for the proxy group of six municipal gas systems.

PGW's five-year historic average of internally-generated funds of 5.34% was also substantially below the five-year averages of 11.93% for the proxy group of six municipal gas systems and the 29.74% and 14.02% for the seven Pennsylvania and seven *Value Line* gas distribution proxy groups, respectively.

Another important ratio is the ratio of total debt to total capital. As shown, PGW's five-year historic average was 84.22%, unfavorably much greater than the five-year average of 54.28% for the proxy group of six municipal gas systems and the 55.30% and 55.44% for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively. Conversely, PGW's five-year historic average of total equity to total capital of 15.78% was unfavorably well below the 45.72% average for the proxy group of six municipal gas systems and the 44.70% and 44.56% for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively.

PGW's debt service coverage (without having to cover its $18.0 million annual fee to the City) was 1.23 times, while the five-year average debt service coverage for the proxy group of six municipal gas systems was 10.06 times. Also shown is that if the fixed charge coverage also had to meet the $18.0 million annual fee to the City, the historic fixed charge coverage would have declined to 1.04 times, well below the minimum 1.2 – 1.3 times required as a minimum even for municipal systems such as PGW with its bottom of investment grade rating as noted by PGW Witness Barbara C. Bisgaier in her direct testimony.

Q. ARE THE RATIOS FOR PGW REASONABLE IF THE INCREASE GRANTED

IN DECEMBER 2008 IS CONTINUED?

A. Yes, I believe they are quite reasonable. They are shown in Column 2 on Schedule 6 and are derived from data provided by PGW presented in this rate filing. As shown, the operating margin is 12.21%, slightly less than the five-year average for the six municipal gas systems of 12.48% shown in Column 4 (and well below the upper end of the range of 13.41% shown on page 1 of Schedule 2), and within the averages of 10.89% and 12.43% (and well below the upper ends of the ranges of 13.59% and 13.14% as shown on page 1 of Schedules 4 and 5, respectively) actually experienced by the seven Pennsylvania and seven *Value Line* investor-owned gas distribution companies, respectively.

Note in Column 2 that PGW's operating ratio declined from its historic average of 88.19% to 82.97%, but is still unfavorably higher than the 77.24% average experienced over the five years by the proxy group of six municipal gas systems and is similar to the 85.26% and 83.07% experienced by the seven Pennsylvania and seven *Value Line* investor-owned gas distribution companies, respectively.

The pre-tax earned return on total capital of 7.29% is greater than the 4.89% experienced by the proxy group of six municipal gas systems, but substantially below the 10.43% and 13.23% actually experienced by the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively.

PGW's 26.31 days cash is substantially less than the 131.13 days cash average of the proxy group of six municipal gas systems.

PGW's internally-generated funds ratio of 9.88% is below the 11.93% five-year average experienced by the proxy group of six municipal gas systems and substantially below the 29.74% and 14.02% experienced by the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively.

PGW's decline in the total debt to total capital ratio from the five-year average of 84.22% to 79.66% is significant, but the 79.66% is still unfavorably much greater than the 54.28% five-year average of the proxy group of six municipal gas systems and the 55.30% and 55.44% averages for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively. Conversely, PGW's historic average total equity to total capital ratio of 15.78% increases to 20.34%. However, the 20.34% is still unfavorably well below the five-year average of 45.72% for the proxy group of six municipal gas systems and the 44.70% and 44.56% averages for the seven Pennsylvania and seven *Value Line* investor-owned gas distribution proxy groups, respectively.

While a significant increase in PGW's debt service coverage from 1.23 times to 1.76 times is laudable, it is still well below the 10.06 times experienced by the proxy group of six municipal gas systems. Also, note in Column 2 that PGW's debt service coverage, if the $18.0 million City fee had to be paid, would decline from 1.76 times to 1.49 times.

Q. PLEASE EXPLAIN THE IMPACT OF THE ADDITIONAL INCREASE REQUESTED IN THIS RATE FILING IN ORDER TO FUND PGW'S OPEB LIABILITY.

A. That information is shown in Column 3 on Schedule 6. As discussed *supra*, the increase would provide no additional wherewithal for PGW to improve its ratios because the entire amount of the increase will be placed into trust in order to fund its

OPEB liability. It is essential that PGW's OPEB liability be funded through rates which will enable it to enhance its financial position over time. Without such increase, PGW would not have the wherewithal to decrease its debt ratio and increase its equity ratio, as it would be necessary to issue additional long-term debt which, rather than enhance would likely degrade its already precarious bottom of investment grade bond rating to junk bond status. Such a situation would be disastrous for PGW and its customers. As shown on PGW's forecast balance sheet, if the Commission grants the funding of the OPEB liability, it will have an opportunity to reduce its debt ratio from about 79.6% to 61.0% over the next five years or by the end of its fiscal year in 2015. While a debt ratio of 61.0% would still be somewhat higher than the other proxy municipal gas systems and the investor-owned utility proxy groups, it would be a significant improvement which surely will lead to a higher bond rating, thereby obviating the alternative – a downgrading to junk bond status. In any event, note that even with the additional increase in order to fund the OPEB liability, PGW's days cash is still only 27.19 days compared to the 131.13 days for the proxy group of six municipal gas systems and the total debt to total capital ratio is 79.62% compared to the 54.28% for the municipal gas systems and approximately 55% for the two investor-owned gas distribution proxy groups.

Also note in Column 3 that the debt service coverage would decline to 1.63 times, without consideration of the $18.0 million annual fee to the City. Debt service coverage of 1.63 times is still substantially below the 10.06 times earned by the proxy group of six municipal gas systems. Note also that the debt service coverage for PGW would decline from the 1.49 times shown in Column 2 (based upon making permanent the full emergency increase granted in December 2008) to 1.40 times, assuming the foregoing and approval of the full amount of the instant request in order to fund its OPEB liability.

Q. IS FIXED CHARGE COVERAGE OF 1.40 TIMES ADEQUATE, ASSUMING THE $18.0 MILLION FEE TO THE CITY IS REQUIRED?

A. Yes, but just minimally so. Based on the testimony of PGW Witness Barbara C. Bisgaier as discussed *supra*, debt service coverage of 1.2 – 1.3 times is an absolute minimum in order to maintain a bottom of investment grade bond rating. Based on my experience, it would be disastrous if PGW's bond rating were to be downgraded below its present S&P rating of BBB-. Such a rating would put it into the junk bond category. It would increase the probability that PGW would be unable to raise all of the external capital required when required and even the possibility that it would be unable to raise any external capital in an extremely tight capital market. Even under the most optimum conditions, if the bonds were downgraded into the junk bond category, the cost rate incurred would be exorbitant and would result in an unjust burden on customers.

Q. WHAT CONCLUSIONS DO YOU DRAW AS A RESULT OF YOUR ANALYSES?

A. I conclude, based upon my analyses, that the rates authorized by this Commission in December 2008 should be continued as well as the full amount of the request in the instant docket, which is essential in order to fund PGW's OPEB liability. Leaving existing rate levels in place and granting the additional request made in this docket will provide the financial wherewithal for PGW to gradually increase its equity ratio (with a concomitant decrease in its debt ratio), a situation which the rating agencies will view favorably. That can be accomplished because PGW will not have to credit realized fund balance in order to record its accrued OPEB liability. The gradual reduction in the debt ratio from approximately 79.6% to 61.0% over the next five plus years should favorably enhance the likelihood that PGW's bond rating will be increased from the bottom of investment grade to a rating somewhat higher. Leaving in place the extraordinary rate increase and authorizing the additional increases necessary to fund PGW's OPEB liability will result in more reasonable yet conservative (vis-à-vis the proxies as discussed *supra*) cash flow ratios, as well as debt-equity ratios, which confirm the reasonableness of PGW's request.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPENDIX A

PROFESSIONAL QUALIFICATIONS

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

PROFESSIONAL QUALIFICATIONS OF FRANK J. HANLEY

EDUCATIONAL BACKGROUND

I am a graduate of Drexel University where I received a Bachelor of Science Degree from the College of Business Administration. The principal courses required for this Degree include accounting, economics, finance and other related courses. I am also Certified by the Society of Utility and Regulatory Financial Analysts, formerly the National Society of Rate of Return Analysts, as a Rate of Return Analyst (CRRA).

PROFESSIONAL EXPERIENCE

In 1959, I was employed by American Water Works Service Company, Inc., which is a wholly-owned subsidiary of American Water Works Company, Inc., the largest investor-owned water works operation in the United States. I was assigned to its Treasury Department in Philadelphia until 1961. During that period of time, I was heavily involved in the development of cash flow projections and negotiations with banks for the establishment of lines of credit for all of the operating and subholding companies in the system, which normally aggregated more than $100 million per year.

In 1961, I was assigned to its Accounting Department where I remained until 1963. During that two-year period, I became intimately familiar with all aspects of a service company accounting system, the nature of the services performed, and the methods of allocating costs. In 1963, I was reassigned to its Treasury Department as a Financial Analyst. My duties consisted of those previously performed, as well as the expanded responsibilities of assisting in the preparation of testimony and exhibits to be presented to various public utility commissions in regard to fair rate of return and other financial matters. I also designed and recommended financing programs for many of American's operating subsidiaries and negotiated sales of long-term debt securities and preferred stock on their behalf either directly with institutional investors or through investment bankers. I was elected Assistant Treasurer of a number of operating subsidiaries in the Fall of 1967, just prior to accepting employment with the Communications and Technical Services Division of the Philco-Ford Corporation located in Fort Washington, Pennsylvania. While in the employ of the Philco-Ford organization, as a Senior Financial Analyst, I had responsibility for the pricing negotiations and analysis of acceptable rates of return to the corporation for all types of contract proposals with various agencies of the U.S. Government and foreign governments.

In the Summer of 1969, I accepted a position with the Financial Division of The Philadelphia National Bank. I was elected Financial Planning Officer of the bank in December 1970. While employed with The Philadelphia National Bank, my responsibilities included preparation of the annual and five-year profit plans. In the compilation of these plans, I had to perform detailed analyses and measure the various levels of profitability for each organizational unit. I also assisted correspondent banks in matters of recapitalization and merger, made recommendations and studies for their use before the various regulatory bodies having jurisdiction over them.

In September 1971, I joined AUS Consultants - Utility Services Group as Vice President. I was elected Senior Vice President in May 1975. I was elected President in September 1989. As a result of a reorganization of AUS Consultants by practice effective January 1, 2007, I am currently a Principal & Director of AUS Consultants.

EXPERT WITNESS QUALIFICATIONS

I have offered testimony as an expert witness on the subjects of fair rate of return and utility financial matters in more than 300 various cases and dockets before the following agencies and courts: before the Alaska Public Utilities Commission and its successor the Regulatory Commission of Alaska, the Arizona Corporation Commission, the Arkansas Public Service Commission, the California Public Utilities Commission, the Public Utilities Control Authority of Connecticut, the Delaware Public Service Commission, the District of Columbia Public Service Commission, the Florida Public Service Commission, Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Public Utility Regulatory Commission, the Iowa Utilities Board, the Public Service Commission of Kentucky, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, Nevada Public Utilities Commission, the New Jersey Board of Public Utilities, the New Mexico State Corporation Commission, the Public Service Commission of the State of New York, the North Carolina Utilities Commission, the Ohio Public Utilities Commission, the Oklahoma Corporation Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, the Tennessee Public Service Commission, the Public Service Board of the State of Vermont, the Virginia State Corporation Commission, the Public Services Commission of the Territory of the U.S. Virgin Islands, the Washington Utilities and Transportation Commission, the Public Service Commission of West Virginia, the Wisconsin Public Service Commission, the Federal Power Commission and its successor the Federal Energy Regulatory Commission. I have testified before the New Jersey Division of Tax Appeals and the United States Bankruptcy Court - Middle District of Pennsylvania with regard to the economic valuation of utility property. Also, I have testified before the U.S. Tax Court in Washington D.C. as an expert witness on the value of closely held utility common stock in a contested Federal Estate Tax case.

In addition, I have appeared as a Staff rate of return witness for the Arizona Corporation Commission, the Delaware Public Service Commission and the Virgin Islands Public Services Commission. I have testified on the fair rate of return on behalf of the City of New Orleans, Louisiana, and also acted as project manager for my firm in representing the City in the 1980-1981 rate proceeding of New Orleans Public Services, Inc. The City of New Orleans then had, as it does now, regulatory authority with regard to the retail rates charged by New Orleans Public Service, Inc., for electric and natural gas service. I have also acted as a consultant to the District of Columbia Public Service Commission itself -- not in the capacity of Staff. AUS Consultants is currently under contract to provide consulting services to the Regulatory Commission of Alaska (RCA). I have provided analyses and recommendations regarding cost of capital to the RCA.

I have testified before a number of local and county regulatory bodies in various states on the subject of fair rate of return on behalf of cable television companies as well as before an arbitration panel in Ohio and a State District Court in Texas. I have testified before the Public Works Committee of the Nebraska State Senate in relation to Legislative Bill 731 which proposed permitting Public Power Districts and Municipalities to enter the Cable Television field.

PROFESSIONAL ASSOCIATIONS,
PUBLICATIONS AND GUEST SPEAKER APPEARANCES

I am a Member of the Society of Utility and Regulatory Financial Analysts (SURFA), formerly known as the National Society of Rate of Return Analysts. I am a Certified Rate of Return Analyst (CRRA). I am on the Advisory Council of New Mexico State University's Center for Public Utilities which is endorsed by the National Association of Regulatory Utility Commissioners (NARUC). I am also a member of the Executive Advisory Council of the Rutgers University School of Business at Camden. AUS Consultants is an associate member of the American Gas Association (AGA) and I am a member of AGA's Rate and Strategic Issues Committee. I am also an associate member of the Energy Association of Pennsylvania and the National Association of Water Companies. AUS Consultants is an associate member of the New Jersey Utilities Association.

I often attend SURFA meetings during which considerable information on the subject of rate of return is exchanged. I have also attended corporate bond rating seminars held by Standard & Poor's Corporation. I continuously review financial publications of institutions such as Standard & Poor's, Moody's Investors' Service, *Value Line Investment Survey*, and periodicals of various agencies of the U.S. Government.

I co-authored an article with A. Gerald Harris entitled "Does Diversification Increase the Cost of Equity Capital?" which was published in the July 15, 1991 issue of Public Utilities Fortnightly. Also, an article which I co-authored with Pauline M. Ahern entitled "Comparable Earnings: New Life for an Old Precept" was published in the American Gas Association's Financial Quarterly Review, Summer 1994. I also authored an article entitled "Why Performance-

Based Incentives Are Essential" which was published in <u>THE CITY GATE</u>, Fall 1995, a magazine published by the Pennsylvania Gas Association. I am a co-author, along with Pauline M. Ahern and Richard A. Michelfelder, of a working paper entitled, "New Approach to Estimating the Cost of Common Equity Capital for Public Utilities", which has been submitted for publication.

I have appeared as a guest speaker before an annual convention of the Mid-American Cable Television Association in Kansas City, Missouri and as a guest panelist on the small water companies' operation seminar of the National Association of Water Companies' 77th Annual Convention in Hollywood, Florida. I addressed the Second Annual Seminar on Regulation of Water Utilities sponsored by N.A.R.U.C., at the University of South Florida's St. Petersburg campus. I have spoken on fair rate of return to the Third and Fourth Annual Utilities Conferences, as well as the special conference on the cost of capital in El Paso, Texas sponsored by New Mexico State University. In 1983 I also made a presentation on the Cost of Capital in Atlantic City, New Jersey, at a seminar co-sponsored by Temple University. I have also addressed the Public Utility Law Section of the American Bar Association's Third Institute on Fundamentals of Ratemaking which was held in Washington, D.C. and I addressed a Conference on Cable Television sponsored by The University of Texas School of Law at Austin, Texas. Also, I addressed a meeting of the New England Water Works Association at Boxborough, Massachusetts, on the subject of Enterprise Financing. In addition, I was a speaker and mock witness in three different Utility Workshops for Attorneys sponsored by the Financial Accounting Institute held in Boston and Washington, D.C. I also was on a panel at the 23rd Financial Forum sponsored by the National Society of Rate of Return Analysts. The topic was Rate of Return Determination in the Diversified and/or Partially

Deregulated Environment. I addressed the 83rd Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was the Cost of Capital Implications of Demand Side Management. In June 1993, I lectured on the cost of capital at the American Gas Association's Gas Rate Fundamentals Course. In October 1993, I was a guest speaker at the University of Wisconsin's Center for Public Utilities – my topic was "Diversification and Corporate Restructuring in the Electric Utility Industry - Trends and Cost of Capital Implications." In October 1994, I was a guest speaker on a panel at the Fourteenth Annual Electric & Natural Gas Conference in Atlanta, Ga., sponsored by the Bonbright Utilities Center of the University of Georgia and the Georgia Public Service Commission. The panel topic was "Responses to Competition and Incentive Rates." In October 1994, I was a guest speaker on a panel at a conference and workshop called "Navigating the Shoals of Cable Rate Regulation" sponsored by EXNET in Washington, D.C. The panel topic was "Rate of Return." Also, in March 1995, I was a guest speaker on a panel at a conference entitled, "Current Issues Challenging the Regulatory Process" sponsored by New Mexico State University - Center for Public Utilities. My panel topic concerned the electric industry and was titled, "Impact of a Competitive Structure on the Financial Markets". In May 1995, I was a guest speaker at the 87th Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was "The Pennsylvania Economy and Utility Regulation: Impact on Industry, Consumers and Investors." In May 1996, I was on a panel at the 28th Financial Forum of the Society of Utility and Regulatory Financial Analysts. The panel's topic was "Revisiting the Risk Premium Approach" and was held in Richmond, Virginia. From 1996 through 2005, I participated as an instructor in 2-3 seminars per year on the "Basics of Regulation" (and the ratemaking process in a changing environment) and also in a program called "A Step Beyond the Basics", all sponsored by New Mexico State University's Center for Public Utilities and NARUC. In March 2002, I was a guest speaker before the Rate and Strategic Issues Committee of the American Gas Association in St. Petersburg, Florida. My topic was Rate of Return Strategies. In December 2002, I was a guest speaker at a seminar entitled, "Service Innovations and Revenue Enhancements for the Energy Distribution Business" sponsored by the American Gas Association in Washington, DC. My topic was "The Impact of Volatile Energy Markets on Rate of Return Strategies". In February 2003, I spoke at the Rutgers University-Camden, NJ M.B.A. Speaker Series. I addressed M.B.A. students and interested faculty on the role of the expert witness in the public utility ratemaking process. In November 2003, 2004, 2007 and 2008, by invitation, I was a Guest Professor at Rutgers University – Camden for classes of undergraduate accounting and finance students. In October 2006, I made a presentation entitled "Mergers & Acquisitions: A Regulatory Perspective" at the Bonbright Center Electric and Natural Gas Conference at the University of Georgia. In February 2008, I taught a course entitled, "The Basics of Cost of Capital Analysis" in Albuquerque, NM as part of a program entitled, "More Basic Practical Training" sponsored by New Mexico State University's Center for Public Utilities.

Exhibit FJH-1

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

EXHIBIT
(Consisting of Six Schedules)

TO ACCOMPANY THE

PREPARED DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRINCIPAL & DIRECTOR
AUS CONSULTANTS

ON BEHALF OF

PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

DECEMBER 2009

Exhibit FJH-1
Schedule 1

Philadelphia Gas Works

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	849,627,000	859,351,000	953,968,000	863,357,000	812,310,000		
Operating Expenses	794,246,000	819,748,000	880,040,000	793,012,000	739,151,000		
Net Operating Income	55,381,000	39,603,000	73,928,000	70,345,000	73,159,000		
Net Income	3,107,000	(16,104,000)	16,759,000	11,272,000	17,159,000		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	49,338,000	51,698,000	6,697,000	15,221,000	3,666,000		
Depreciation and Amortization (2)	42,868,000	39,708,000	37,955,000	39,547,000	38,868,000		
Total Non-Cash Expenses			36,275,000	36,953,000	42,668,000		
Interest Income (3)			3,345,000	(6,701,000)	1,050,000		
NOI + All Taxes	55,381,000	39,603,000	73,928,000	70,345,000	73,159,000		
Net Income + All Taxes	3,107,000	(16,104,000)	16,759,000	11,272,000	17,159,000		
All Operating Expenses - Taxes	794,246,000	819,748,000	880,040,000	793,012,000	739,151,000		
Scheduled Long-Term Principal Payment			39,591,000	42,271,000	41,813,000		
Total Annual Interest Payment			65,687,000	63,851,000	59,580,000		
Funds Available for Debt Service (4)	146,498,000 (5)	130,680,000 (5)	131,548,000	118,597,000	116,877,000		
Total Annual Debt Service (6)	106,932,847 (5)	104,544,000 (5)	105,278,000	106,122,000	101,393,000		
Total Proprietary Capital	226,408,000	223,301,000	239,405,000	222,646,000	211,374,000		
Total Long-Term Debt	1,203,193,000	1,245,787,000	1,115,722,000	1,118,101,000	955,327,000		
Total Short-Term Debt	90,000,000	94,600,000	55,000,000	49,900,000	95,750,000		
Total Capital	1,519,601,000	1,563,688,000	1,410,127,000	1,390,647,000	1,262,451,000		
Operating Margin (7)	6.52%	4.61%	7.75%	8.15%	9.01%	7.21%	4.61% - 9.01%
Operating Ratio (8)	88.44%	90.77%	88.27%	87.27%	86.21%	88.19%	86.21% - 90.77%
Pre-Tax Earned Return on Total Capital (9)	3.64%	2.53%	5.24%	5.06%	5.79%	4.45%	2.53% - 5.79%
Days Cash (10)	23.97	24.19	2.90	7.37	1.91	12.07	1.91 - 24.19
Interally Generated Funds (11)	5.41%	2.75%	5.74%	5.89%	6.90%	5.34%	2.75% - 6.90%
Total Debt / Total Capital	85.10%	85.72%	83.02%	83.99%	83.26%	84.22%	83.02% - 85.72%
Total Equity / Total Capital	14.90%	14.28%	16.98%	16.01%	16.74%	15.78%	14.28% - 16.98%
Debt Service Coverage (12) (times)	1.37 (5)	1.25 (5)	1.25	1.12	1.15	1.23	1.12 - 1.37
Debt Service Coverage Including $18 M City Fee (times)	1.16 (5)	1.04 (5)	1.07	0.96	0.98	1.04	0.96 - 1.16

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) PGW provided.
(6) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(7) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(8) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(9) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(10) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(11) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(12) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports provided by PGW

Proxy Group of Six Municipal Gas Systems

	2008	2007	2006	2005	2004	Five-Year Average	Range		
Operating Revenues	740,528,100	659,612,560	648,848,050	637,755,562	536,433,477				
Operating Expenses	644,344,156	573,250,891	572,843,328	552,205,016	476,533,614				
Net Operating Income	96,183,944	86,361,669	76,004,722	85,550,546	59,899,864				
Net Income	23,040,818	(145,370)	7,529,326	17,587,335	6,352,539				
Taxes Other than Income Taxes (1)	-	-	-	-	-				
Income Taxes	-	-	-	-	-				
Provision for Deferred Income Taxes	-	-	-	-	-				
Provision for Deferred Income Taxes - Credit	-	-	-	-	-				
Investment Tax Credit Adjustments	-	-	-	-	-				
Sum of all Taxes	-	-	-	-	-				
Cash and Cash Equivalents	144,015,251	193,022,423	202,268,330	178,015,559	166,087,604				
Non-Cash Expenses (2)	71,339,894	67,721,639	66,811,934	63,390,351	60,598,626				
Depreciation and Amortization (3)	14,881,798	14,114,120	14,592,374	14,149,169	13,654,784				
Interest Income (3)	913,103	359,270	772,616	1,017,654	4,336,174				
NOI + All Taxes	96,183,944	86,361,669	76,004,722	85,550,546	59,899,864				
Net Income + All Taxes	23,040,818	(145,370)	7,529,326	17,587,335	6,352,539				
All Operating Expenses - Taxes	644,344,156	573,250,891	572,843,328	552,205,016	476,533,614				
Scheduled Long-Term Principal Payment	4,035,250	3,807,750	3,768,750	3,581,250	3,376,250				
Total Annual Interest Payment	6,857,951	5,979,894	5,773,873	5,477,888	5,254,431				
Funds Available for Debt Service (4)	111,978,845	100,835,059	91,369,712	100,717,369	77,890,821				
Total Annual Debt Service (5)	10,893,201	9,787,644	9,542,623	9,059,138	8,630,681				
Total Proprietary Capital	372,250,544	908,049,332	881,461,912	877,921,362	838,966,805				
Total Long-Term Debt	1,030,514,000	935,803,833	867,628,000	816,391,000	770,206,667				
Total Short-Term Debt	20,120,000	15,803,333	8,333,333	8,333,333	8,333,333				
Total Capital	1,422,884,544	1,859,656,499	1,757,423,246	1,702,645,695	1,617,506,805				
Operating Margin (6)	12.99%	13.09%	11.71%	13.41%	11.17%	12.48%	11.17%	-	13.41%
Operating Ratio (7)	77.38%	76.64%	77.99%	76.65%	77.54%	77.24%	76.64%	-	77.99%
Pre-Tax Earned Return on Total Capital (8)	6.76%	4.64%	4.32%	5.02%	3.70%	4.89%	3.70%	-	6.76%
Days Cash (9)	91.74	139.37	145.90	132.92	145.75	131.13	91.74	-	145.90
Interally Generated Funds (10)	12.75%	10.24%	11.46%	12.70%	12.48%	11.93%	10.24%	-	12.75%
Total Debt / Total Capital	73.84%	51.17%	49.84%	48.44%	48.13%	54.28%	48.13%	-	73.84%
Total Equity / Total Capital	26.16%	48.83%	50.16%	51.56%	51.87%	45.72%	26.16%	-	51.87%
Debt Service Coverage (11) (times)	10.28	10.30	9.57	11.12	9.02	10.06	9.02	-	11.12

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(6) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(7) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(8) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(9) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(10) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(11) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports or Fitch Ratings Reports

Citizens Gas & Coke Utility

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	542,443,000	522,492,000	622,825,000	577,841,000	514,753,000		
Operating Expenses	509,555,000	493,275,000	624,250,000	556,070,000	490,249,000		
Net Operating Income	32,888,000	29,217,000	(1,425,000)	21,771,000	24,504,000		
Net Income	19,887,000	(28,580,000)	3,842,000	20,992,000	19,517,000		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	29,132,000	21,922,000	81,513,000	31,210,000	43,525,000		
Non-Cash Expenses (2)	30,257,000	24,810,000	29,072,000	26,862,000	24,032,000		
Depreciation and Amortization (3)	33,690,000	28,076,000	30,707,000	30,216,000	27,532,000		
Interest Income (3)	-	-	-	-	-		
NOI + All Taxes	32,888,000	29,217,000	(1,425,000)	21,771,000	24,504,000		
Net Income + All Taxes	19,887,000	(28,580,000)	3,842,000	20,992,000	19,517,000		
All Operating Expenses - Taxes	509,555,000	493,275,000	624,250,000	556,070,000	490,249,000		
Scheduled Long-Term Principal Payment	15,201,000	14,306,000	13,350,000	12,620,000	12,030,000		
Total Annual Interest Payment	25,341,000	22,064,000	22,067,000	21,101,000	20,297,000		
Funds Available for Debt Service (4)	66,578,000	57,293,000	29,282,000	51,987,000	52,036,000		
Total Annual Debt Service (5)	40,542,000	36,370,000	35,417,000	33,721,000	32,327,000		
Total Proprietary Capital	226,751,000	216,805,000	264,544,000	242,665,000	247,691,000		
Total Long-Term Debt	553,972,000	524,856,000	526,447,000	532,901,000	537,100,000		
Total Short-Term Debt	68,000,000	50,000,000	50,000,000	50,000,000	50,000,000		
Total Capital	848,723,000	791,661,000	840,991,000	825,566,000	834,791,000		
Operating Margin (6)	6.06%	5.59%	-0.23%	3.77%	4.76%	3.99%	-0.23% - 6.06%
Operating Ratio (7)	88.36%	89.66%	95.56%	91.58%	90.57%	91.15%	88.36% - 95.56%
Pre-Tax Earned Return on Total Capital (8)	3.87%	3.69%	-0.17%	2.64%	2.94%	2.59%	-0.17% - 3.87%
Days Cash (9)	22.18	17.08	49.99	21.53	34.08	28.97	17.08 - 49.99
Interally Generated Funds (10)	9.24%	-0.72%	5.28%	8.28%	8.46%	6.11%	-0.72% - 8.46%
Total Debt / Total Capital	73.28%	72.61%	68.54%	70.61%	70.33%	71.08%	68.54% - 73.28%
Total Equity / Total Capital	26.72%	27.39%	31.46%	29.39%	29.67%	28.92%	26.72% - 31.46%
Debt Service Coverage (11) (times)	1.64	1.58	0.83	1.54	1.61	1.44	0.83 - 1.64

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(6) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(7) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(8) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(9) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(10) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(11) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports provided on Company website

Colorado Springs Utilities

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	756,774,000	721,356,000	678,531,000	671,847,000	590,991,000		
Operating Expenses	721,929,000	654,521,000	617,183,000	599,218,000	551,295,000		
Net Operating Income	34,845,000	66,835,000	61,348,000	72,629,000	39,696,000		
Net Income	N/A	N/A	N/A	N/A	N/A		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	138,068,000	198,246,000	208,989,000	163,027,000	101,610,000		
Non-Cash Expenses (2)	94,133,000	91,568,000	85,671,000	82,849,000	79,528,000		
Depreciation and Amortization	N/A	N/A	N/A	N/A	N/A		
Interest Income	N/A	N/A	N/A	N/A	N/A		
NOI + All Taxes	34,845,000	66,835,000	61,348,000	72,629,000	39,696,000		
Net Income + All Taxes	N/A	N/A	N/A	N/A	N/A		
All Operating Expenses - Taxes	721,929,000	654,521,000	617,183,000	599,218,000	551,295,000		
Scheduled Long-Term Principal Payment	N/A	N/A	N/A	N/A	N/A		
Total Annual Interest Payment	N/A	N/A	N/A	N/A	N/A		
Funds Available for Debt Service (3)	162,632,000	201,908,000	186,995,000	193,881,000	161,972,000		
Total Annual Debt Service (4)	79,332,683	91,361,086	86,974,419	80,783,750	71,669,027		
Total Proprietary Capital	1,015,368,000	1,565,472,000	1,470,515,000	1,394,151,000	1,275,458,000		
Total Debt	1,614,433,000	1,225,767,000	1,193,407,000	1,256,147,000	1,105,865,000		
	-	-	-	-	-		
Total Capital	2,629,801,000	2,791,239,000	2,663,922,000	2,650,298,000	2,381,323,000		
Operating Margin (5)	4.60%	9.27%	9.04%	10.81%	6.72%	8.09%	4.60% - 10.81%
Operating Ratio (6)	82.96%	78.04%	78.33%	76.86%	79.83%	79.20%	76.86% - 82.96%
Pre-Tax Earned Return on Total Capital (7)	1.33%	2.39%	2.30%	2.74%	1.67%	2.09%	1.33% - 2.74%
Days Cash (8)	80.27	128.54	143.52	115.24	78.61	109.24	78.61 - 143.52
Interally Generated Funds (9)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Debt / Total Capital	61.39%	43.91%	44.80%	47.40%	46.44%	48.79%	43.91% - 61.39%
Total Equity / Total Capital	38.61%	56.09%	55.20%	52.60%	53.56%	51.21%	38.61% - 56.09%
Debt Service Coverage (3) (times)	2.05	2.21	2.15	2.40	2.26	2.21	2.05 - 2.40

N/A = Not Available

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Provided by Fitch Ratings.
(4) Calculated by dividing funds available for debt service by debt service coverage.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(6) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(7) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(8) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(9) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Fitch Ratings, August 29, 2009.

CPS Energy

	2009	2008	2007	2006	2005	Five-Year Average	Range
Operating Revenues	2,151,341,000	1,860,677,000	1,770,086,000	1,682,719,000	1,422,405,000		
Operating Expenses	1,711,171,000	1,460,767,000	1,392,613,000	1,304,854,000	1,123,251,000		
Net Operating Income	440,170,000	399,910,000	377,473,000	377,865,000	299,154,000		
Net Income	N/A	N/A	N/A	N/A	N/A		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	666,306,000	893,300,000	892,821,000	843,541,000	824,326,000		
Non-Cash Expenses (2)	280,572,824	266,428,172	261,086,385	246,804,292	235,702,357		
Depreciation and Amortization	N/A	N/A	N/A	N/A	N/A		
Interest Income	N/A	N/A	N/A	N/A	N/A		
NOI + All Taxes	440,170,000	399,910,000	377,473,000	377,865,000	299,154,000		
Net Income + All Taxes	N/A	N/A	N/A	N/A	N/A		
All Operating Expenses - Taxes	1,711,171,000	1,460,767,000	1,392,613,000	1,304,854,000	1,123,251,000		
Scheduled Long-Term Principal Payment	N/A	N/A	N/A	N/A	N/A		
Total Annual Interest Payment	N/A	N/A	N/A	N/A	N/A		
Funds Available for Debt Service (3)	774,375,000	760,295,000	714,828,000	667,828,000	570,775,000		
Total Annual Debt Service (4)	335,227,273	332,006,550	294,167,901	275,961,983	255,952,915		
Total Proprietary Capital	311,551,000	3,029,709,000	2,919,361,000	2,994,361,000	2,885,601,000		
Total Debt	3,992,826,000	3,842,621,000	3,469,306,000	3,098,751,000	2,966,147,000		
	-	-	-	-	-		
Total Capital	4,304,377,000	6,872,330,000	6,388,667,000	6,093,112,000	5,851,748,000		
Operating Margin (5)	20.46%	21.49%	21.33%	22.46%	21.03%	21.35%	20.46% - 22.46%
Operating Ratio (6)	66.50%	64.19%	63.92%	62.88%	62.40%	63.98%	62.40% - 66.50%
Pre-Tax Earned Return on Total Capital (7)	10.23%	5.82%	5.91%	6.20%	5.11%	6.65%	5.11% - 10.23%
Days Cash (8)	170.00	273.00	288.00	291.00	339.00	272.20	170.00 - 339.00
Interally Generated Funds (9)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Debt / Total Capital	92.76%	55.91%	54.30%	50.86%	50.69%	60.91%	50.69% - 92.76%
Total Equity / Total Capital	7.24%	44.09%	45.70%	49.14%	49.31%	39.09%	49.31% - 7.24%
Debt Service Coverage (3) (times)	2.31	2.29	2.43	2.42	2.23	2.34	2.23 - 2.43

N/A = Not Available

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Provided by Fitch Ratings.
(4) Calculated by dividing funds available for debt service by debt service coverage.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(6) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(7) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(8) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(9) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Fitch Ratings, May 20, 2009.

Long Beach Gas & Oil

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	123,085,000	99,648,000	107,481,000	98,998,000	83,752,000		
Operating Expenses	109,463,000	88,250,000	100,027,000	87,115,000	76,166,000		
Net Operating Income	13,622,000	11,398,000	7,454,000	11,883,000	7,586,000		
Net Income	14,418,000	12,162,000	12,856,000	17,293,000	12,514,000		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	280,000	6,029,000	10,812,000	12,872,000	10,282,000		
Non-Cash Expenses (2)	3,308,000	3,098,000	3,242,000	3,007,000	3,017,000		
Depreciation and Amortization (3)	3,303,000	3,098,000	3,242,000	3,007,000	3,107,000		
Interest Income (3)	43,000	1,057,000	674,000	562,000	491,000		
NOI + All Taxes	13,622,000	11,398,000	7,454,000	11,883,000	7,586,000		
Net Income + All Taxes	14,418,000	12,162,000	12,856,000	17,293,000	12,514,000		
All Operating Expenses - Taxes	109,463,000	88,250,000	100,027,000	87,115,000	76,166,000		
Scheduled Long-Term Principal Payment	940,000	925,000	905,000	885,000	655,000		
Total Annual Interest Payment	523,000	626,000	401,000	447,000	433,000		
Funds Available for Debt Service (4)	16,968,000	15,553,000	11,370,000	15,452,000	11,184,000		
Total Annual Debt Service (5)	1,463,000	1,551,000	1,306,000	1,332,000	1,088,000		
Total Proprietary Capital	67,177,000	64,470,000	63,710,000	67,855,000	66,060,000		
Total Long-Term Debt	21,853,000	20,759,000	14,148,000	7,267,000	8,028,000		
Total Short-Term Debt	-	-	-	-	-		
Total Capital	89,030,000	85,229,000	77,858,000	75,122,000	74,088,000		
Operating Margin (6)	11.07%	11.44%	6.94%	12.00%	9.06%	10.10%	6.94% - 12.00%
Operating Ratio (7)	86.25%	85.45%	90.05%	84.96%	87.34%	86.81%	84.96% - 90.05%
Pre-Tax Earned Return on Total Capital (8)	15.30%	13.37%	9.57%	15.82%	10.24%	12.86%	9.57% - 15.82%
Days Cash (9)	0.96	25.84	40.77	55.86	51.31	34.95	0.96 - 55.86
Interally Generated Funds (10)	14.40%	15.31%	14.98%	20.51%	18.54%	16.75%	14.40% - 20.51%
Total Debt / Total Capital	24.55%	24.36%	18.17%	9.67%	10.84%	17.52%	9.67% - 24.55%
Total Equity / Total Capital	75.45%	75.64%	81.83%	90.33%	89.16%	82.48%	75.45% - 90.33%
Debt Service Coverage (11) (times)	11.60	10.03	8.71	11.60	10.28	10.44	8.71 - 11.60

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(6) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(7) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(8) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(9) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(10) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(11) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports provided on Company website

Memphis Light, Gas, & Water

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	523,317,000	442,382,000	432,930,000	483,626,000	363,345,000		
Operating Expenses	482,970,000	443,611,000	432,660,000	465,181,000	376,160,000		
Net Operating Income	40,347,000	(1,229,000)	270,000	18,445,000	(12,815,000)		
Net Income	42,983,000	3,927,000	3,019,000	21,322,000	(7,842,000)		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	26,295,000	36,197,000	16,618,000	14,850,000	15,258,000		
Non-Cash Expenses (2)	12,377,000	13,286,000	15,150,000	14,814,000	14,803,000		
Depreciation and Amortization (3)	12,377,000	16,048,000	15,150,000	14,814,000	14,803,000		
Interest Income (3)	3,547,000	-	2,297,000	3,113,000	16,619,000		
NOI + All Taxes	40,347,000	(1,229,000)	270,000	18,445,000	(12,815,000)		
Net Income + All Taxes	42,983,000	3,927,000	3,019,000	21,322,000	(7,842,000)		
All Operating Expenses - Taxes	482,970,000	443,611,000	432,660,000	465,181,000	376,160,000		
Scheduled Long-Term Principal Payment	-	-	-	-	-		
Total Annual Interest Payment	1,149,000	720,000	-	-	-		
Funds Available for Debt Service (4)	56,271,000	14,819,000	17,717,000	36,372,000	18,607,000		
Total Annual Debt Service (5)	1,149,000	720,000	-	-	-		
Total Proprietary Capital	410,830,000	384,889,000	395,600,000	403,855,000	405,092,000		
Total Long-Term Debt	-	-	-	-	-		
Total Short-Term Debt	35,000,000	40,000,000	-	-	-		
Total Capital	445,830,000	424,889,000	395,600,000	403,855,000	405,092,000		
Operating Margin (6)	7.71%	-0.28%	0.06%	3.81%	-3.53%	1.56%	-3.53% - 7.71%
Operating Ratio (7)	89.93%	97.27%	96.44%	93.12%	99.45%	95.24%	89.93% - 99.45%
Pre-Tax Earned Return on Total Capital (8)	9.05%	-0.29%	0.07%	4.57%	-3.16%	2.05%	3.16% - 9.05%
Days Cash (9)	20.39	30.70	14.53	12.04	15.41	18.61	12.04 - 30.70
Interally Generated Funds (10)	10.58%	3.89%	4.20%	7.47%	1.92%	5.61%	1.92% - 10.58%
Total Debt / Total Capital	7.85%	9.41%	0.00%	0.00%	0.00%	3.45%	0.00% - 9.41%
Total Equity / Total Capital	92.15%	90.59%	100.00%	100.00%	100.00%	96.55%	90.59% - 100.00%
Debt Service Coverage (11) (times)	48.97	20.58	N/A	N/A	N/A	34.78	20.58 - 48.97

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes deprereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(6) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(7) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(8) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(9) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(10) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(11) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports provided on Company website

Metropolitan Utilities District

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	346,208,598	311,120,362	281,235,299	311,502,371	243,354,863		
Operating Expenses	330,976,935	299,081,346	270,326,969	300,792,096	242,080,682		
Net Operating Income	15,231,663	12,039,016	10,908,330	10,710,275	1,274,181		
Net Income	14,875,272	11,909,520	10,400,304	10,742,339	1,221,155		
Taxes Other than Income Taxes (1)	-	-	-	-	-		
Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	-	-	-	-	-		
Cash and Cash Equivalents	4,010,503	2,440,535	2,856,977	2,593,355	1,524,622		
Non-Cash Expenses (2)	7,391,538	7,139,661	6,650,218	6,005,813	6,509,400		
Depreciation and Amortization (3)	10,157,192	9,234,481	9,270,496	8,559,674	9,177,134		
Interest Income (3)	62,413	380,079	119,464	395,617	234,697		
NOI + All Taxes	15,231,663	12,039,016	10,908,330	10,710,275	1,274,181		
Net Income + All Taxes	14,875,272	11,909,520	10,400,304	10,742,339	1,221,155		
All Operating Expenses - Taxes	330,976,935	299,081,346	270,326,969	300,792,096	242,080,682		
Scheduled Long-Term Principal Payment	-	-	820,000	820,000	820,000		
Total Annual Interest Payment	418,804	509,575	627,490	363,553	287,723		
Funds Available for Debt Service (4)	25,451,268	21,653,576	20,298,290	19,665,566	10,686,012		
Total Annual Debt Service (5)	418,804	509,575	1,447,490	1,183,553	1,107,723		
Total Proprietary Capital	201,826,266	186,950,994	175,041,474	164,641,170	153,898,831		
Total Long-Term Debt	-	820,000	2,460,000	3,280,000	4,100,000		
Total Short-Term Debt	17,720,000	4,820,000	-	-	-		
Total Capital	219,546,266	192,590,994	177,501,474	167,921,170	157,998,831		
Operating Margin (6)	4.40%	3.87%	3.88%	3.44%	0.52%	3.22%	0.52% - 4.40%
Operating Ratio (7)	93.47%	93.84%	93.76%	94.63%	96.80%	94.50%	93.47% - 96.80%
Pre-Tax Earned Return on Total Capital (8)	6.94%	6.25%	6.15%	6.38%	0.81%	5.30%	0.81% - 6.94%
Days Cash (9)	4.52	3.05	3.95	3.21	2.36	3.42	2.36 - 4.52
Interally Generated Funds (10)	6.43%	6.12%	6.06%	5.38%	3.18%	5.43%	3.18% - 6.43%
Total Debt / Total Capital	8.07%	2.93%	1.39%	1.95%	2.59%	3.39%	1.39% - 8.07%
Total Equity / Total Capital	91.93%	97.07%	98.61%	98.05%	97.41%	96.61%	91.93% - 98.61%
Debt Service Coverage (11) (times)	60.77	42.49	14.02	16.62	9.65	28.71	9.65 - 60.77

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) From statement of cash flows.
(4) Calculated by adding operating income, depreciation and amortization from the statement of cash flows, and the interest income from the statement of cash flows.
(5) Calculated by adding the scheduled long-term principal to the total annual interest payment.
(6) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(7) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(8) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(9) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(10) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(11) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Annual Reports provided on Company website

Proxy Group of Six Municipal Gas Systems
Selection Criteria
2004-2008, Inclusive

Selection Criteria:

PGW is the largest municipal gas system in the United States. The six companies selected are the next six largest municipal gas systems after PGW all serve at least 125,000 customers as of November 23, 2009 according to the American Public Gas Association (APGA).

The following six municipal gas systems met the above criteria:

Citizens Gas & Coke Utility (Indianapolis, IN)
Colorado Springs Utilities (Colorado Springs, CO)
CPS Energy (San Antonio, TX)
Long Beach Gas and Oil (Long Beach, CA)
Memphis Light, Gas, & Water (Memphis, TN)
Metropolitan Utilities District (Omaha, NE)

Source of Information: www.apga.org

Top 100 Municipal Gas Systems

(as of data collected November 23, 2009)

Rank	COMPANY	CUSTOMERS	STATE	CITY
1.	Philadelphia Gas Works	514,511	PA	Philadelphia
2.	Memphis Light, Gas & Water	319,983	TN	Memphis
3.	CPS Energy	319,125	TX	San Antonio
4.	Citizens Energy Group	269,272	IN	Indianapolis
5.	Metropolitan Utilities District	207,553	NE	Omaha
6.	Colorado Springs Utilities	185,296	CO	Colorado Springs
7.	Long Beach Gas and Oil	148,568	CA	Long Beach
8.	Richmond Department of Public Utilities	107,600	VA	Richmond
9.	Knoxville Utilities Board	94,469	TN	Knoxville
10.	City Utilities of Springfield	83,077	MO	Springfield
11.	Corpus Christi Gas Dept	58,680	TX	Corpus Christi
12.	Austell Gas System	56,840	GA	Austell
13.	Middle Tennessee Natural Gas	54,829	TN	Smithville
14.	City of Mesa	52,780	AZ	Mesa
15.	York County Natural Gas Authority	52,311	SC	Rock Hill
16.	City of Lawrenceville	47,584	GA	Lawrenceville
17.	Huntsville Utilities	46,690	AL	Huntsville
18.	Energy Services of Pensacola	45,607	FL	Pensacola
19.	Okaloosa Gas District	37,795	FL	Valparaiso
20.	Fort Hill Natural Gas Authority	37,512	SC	Easley
21.	Gainesville Regional Utilities	33,622	FL	Gainesville
22.	City of Buford	30,521	GA	Buford
23.	Southeast Alabama Gas District	29,985	AL	Andalusia
24.	Jackson Energy Authority	29,134	TN	Jackson
25.	City of Las Cruces	26,758	NM	Las Cruces
26.	Tallahassee Gas Utility Department	26,743	FL	Tallahassee
27.	Duluth Water & Gas Department	24,970	MN	Duluth
28.	Marshall County Gas District	24,210	AL	Guntersville
29.	City of Palo Alto	23,870	CA	Palo Alto
30.	City of Hamilton	23,617	OH	Hamilton
31.	Albany Water Gas & Light Company	22,376	GA	Albany
32.	Trussville Utilities Board	22,335	AL	Trussville
33.	Clarksville Water & Gas Department	22,020	TN	Clarksville
34.	City of Alexandria	21,567	LA	Alexandria
35.	Greenville Utilities Commission	21,522	NC	Greenville
36.	Clearwater Gas System	19,762	FL	Clearwater
37.	Greer Commission of Public Works	19,754	SC	Greer
38.	Greenwood Commission of Public Works	18,832	SC	Greenwood

Philadelphia Gas Works
Comparison of Bond Ratings, Business Risk and Financial Risk Profiles for the
Proxy Group of Six Municipal Gas Systems

	Moody's Bond Rating		Standard & Poor's Bond Rating		Fitch Bond Rating	
	Bond Rating	Numerical Weighting (1)	Bond Rating	Numerical Weighting (1)	Credit Rating	Numerical Weighting (1)
Philadelphia Gas Works	Baa2	9.0	BBB-	10.0	NR	NA
Proxy Group of Six Municipal Gas Systems						
Citizens Gas & Coke Utility (Indianapolis, IN)	A2	6.0	AA-	4.0	NR	NA
Colorado Springs Utilities	NR	NA	NR	NA	AA	3.0
CPS Energy (San Antonio, TX)	NR	NA	NR	NA	AA+	2.0
Long Beach Gas and Oil	A1	5.0	A	6.0	NR	NA
Memphis Light, Gas, & Water	NR	NA	AA (2)	3.0	NR	NA
Metropolitan Utilties District (Omaha NE)	Aa2	3.0	AA	3	AA	3.0
Average	A1	4.7	AA-	4.0	AA	2.7

Notes:
(1) On page 2 of this Schedule.
(2) Rating on electric system subordinate revenue bonds - gas system not rated.

Philadelphia Gas Works
Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings,
Standard & Poor's Credit Ratings, and
Standard & Poor's Business and Financial Risk Profiles

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's /Fitch's Bond / Credit Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-

Proxy Group of Seven Pennsylvania Investor-Owned Natural Gas Distribution Companies

	2008	2007	2006	2005	2004	Five-Year Average	Range		
Operating Revenues	567,411,997	503,268,354	485,669,144	512,875,949	465,345,593				
Operating Expenses	528,560,635	465,263,919	445,904,755	468,411,917	416,684,353				
Net Operating Income	38,851,362	38,004,435	39,764,390	44,464,032	48,661,240				
Net Income	72,867,392	128,268,029	106,827,813	129,768,388	144,724,810				
Taxes Other than Income Taxes (1)	2,489,579	1,975,669	2,179,937	2,004,480	3,064,546				
Income Taxes	3,445,926	7,866,508	12,673,411	1,135,314	1,922,981				
Provision for Deferred Income Taxes	23,014,173	14,674,893	3,567,702	17,929,963	18,455,507				
Provision for Deferred Income Taxes - Credit	(10,338,366)	(7,938,951)	(13,944,650)	(9,272,172)	(8,590,322)				
Investment Tax Credit Adjustments	(250,491)	(245,274)	(245,907)	(245,508)	(288,612)				
Sum of all Taxes	18,360,822	16,332,846	4,230,493	11,552,078	14,564,100				
Cash and Cash Equivalents	15,316,006	9,963,926	10,209,096	18,818,178	7,808,444				
Non-Cash Expenses (2)	19,478,309	18,762,140	20,227,551	19,333,448	19,325,154				
NOI + All Taxes	57,212,184	54,337,281	43,994,882	56,016,109	63,225,341				
Net Income + All Taxes	91,228,214	144,600,875	111,058,306	141,320,466	159,288,910				
All Operating Expenses - Taxes	510,199,813	448,931,073	441,674,262	456,859,839	402,120,253				
Total Proprietary Capital	287,762,957	264,915,551	249,638,272	233,003,049	223,154,589				
Total Long-Term Debt	250,221,608	229,253,438	220,310,738	185,083,050	178,214,950				
Total Short-Term Debt	135,274,444	109,375,052	103,624,549	95,254,000	63,795,650				
Total Capital	673,259,008	603,544,042	573,573,559	513,340,099	465,165,189				
Operating Margin (3)	10.08%	10.80%	9.06%	10.92%	13.59%	10.89%	9.06%	-	13.59%
Operating Ratio (4)	86.48%	85.48%	86.78%	85.31%	82.26%	85.26%	82.26%	-	86.78%
Pre-Tax Earned Return on Total Capital (5)	9.46%	10.24%	7.76%	11.55%	13.15%	10.43%	7.76%	-	13.15%
Interally Generated Funds (6)	19.51%	32.46%	27.03%	31.32%	38.38%	29.74%	19.51%	-	38.38%
Total Debt / Total Capital	57.26%	56.11%	56.48%	54.61%	52.03%	55.30%	52.03%	-	57.26%
Total Equity / Total Capital	42.74%	43.89%	43.52%	45.39%	47.97%	44.70%	42.74%	-	47.97%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

Columbia Gas Company of Pennsylvania

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	781,900,361	650,518,672	575,393,697	652,100,658	551,432,730		
Operating Expenses	741,684,997	618,969,544	545,995,407	613,471,764	506,402,598		
Net Operating Income	40,215,364	31,549,128	29,398,290	38,628,894	45,030,132		
Net Income	29,505,432	26,305,221	22,388,342	28,359,231	36,808,786		
Taxes Other than Income Taxes (1)	1,071,308	1,589,331	1,720,157	1,932,451	2,020,134		
Income Taxes	(15,127,353)	4,286,255	22,277,016	7,165,102	1,856,688		
Provision for Deferred Income Taxes	32,444,073	10,389,669	8,921,888	14,127,282	22,471,587		
Provision for Deferred Income Taxes - Credit	(3,703,372)	(3,890,779)	(22,634,847)	(4,156,685)	(2,798,765)		
Investment Tax Credit Adjustments	(360,252)	(360,240)	(360,252)	(360,236)	(360,252)		
Sum of all Taxes	14,324,404	12,014,236	9,923,962	18,707,914	23,189,392		
Cash and Cash Equivalents	25,367,866	13,152,100	11,143,003	3,170,316	2,123,592		
Non-Cash Expenses (2)	20,084,725	18,703,311	17,739,960	17,380,545	16,702,965		
NOI + All Taxes	54,539,768	43,563,364	39,322,252	57,336,808	68,219,524		
Net Income + All Taxes	43,829,836	38,319,457	32,312,304	47,067,145	59,998,178		
All Operating Expenses - Taxes	727,360,593	606,955,308	536,071,445	594,763,850	483,213,206		
Total Proprietary Capital	318,891,332	291,310,993	256,009,376	239,728,020	227,888,110		
Total Long-Term Debt	285,215,000	263,215,000	205,215,000	185,215,000	167,372,000		
Total Short-Term Debt	-	-	-	-	17,843,000		
Total Capital	604,106,332	554,525,993	461,224,376	424,943,020	413,103,110		
Operating Margin (3)	6.98%	6.70%	6.83%	8.79%	12.37%	8.33%	6.70% - 12.37%
Operating Ratio (4)	90.46%	90.43%	90.08%	88.54%	84.60%	88.82%	84.60% - 90.43%
Pre-Tax Earned Return on Total Capital (5)	9.03%	7.86%	8.53%	13.49%	16.51%	11.08%	7.86% - 16.51%
Interally Generated Funds (6)	8.17%	8.77%	8.70%	9.88%	13.91%	9.89%	8.17% - 13.91%
Total Debt / Total Capital	47.21%	47.47%	44.49%	43.59%	44.84%	45.52%	43.59% - 47.47%
Total Equity / Total Capital	52.79%	52.53%	55.51%	56.41%	55.16%	54.48%	52.79% - 56.41

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

Dominion Peoples (People's Natural Gas Company)

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	534,786,115	469,869,748	505,284,379	551,526,165	462,548,198		
Operating Expenses	478,058,994	406,994,152	462,007,938	485,042,668	396,514,474		
Net Operating Income	56,727,121	62,875,596	43,276,441	66,483,497	66,033,724		
Net Income	59,100,078	33,401,281	19,459,770 (1)	43,185,945	52,539,987		
Taxes Other than Income Taxes (2)	4,854,355	2,940,237	3,390,245	4,691,900	5,089,180		
Income Taxes	(5,693,643)	(5,114,790)	32,493,047	(4,842,185)	10,744,538		
Provision for Deferred Income Taxes	57,178,905	31,770,640	(1,610,865)	38,331,390	29,606,229		
Provision for Deferred Income Taxes - Credit	(30,675,430)	(8,690,045)	(17,611,431)	(17,060,664)	(23,298,000)		
Investment Tax Credit Adjustments	(472,556)	(430,805)	(429,154)	(449,000)	(457,000)		
Sum of all Taxes	25,191,631	20,475,237	16,231,842	20,671,441	21,684,947		
Cash and Cash Equivalents	3,903,430	3,054,176	3,161,451	6,257,648	1,758,713		
Non-Cash Expenses (3)	20,505,813	20,119,123	29,006,263	20,039,077	18,954,358		
NOI + All Taxes	81,918,752	83,350,833	59,508,283	87,154,938	87,718,671		
Net Income + All Taxes	84,291,709	53,876,518	35,691,612	63,857,386	74,224,934		
All Operating Expenses - Taxes	452,867,363	386,518,915	445,776,096	464,371,227	374,829,527		
Total Proprietary Capital	248,801,035	244,697,211	235,334,938	341,393,586	337,505,650		
Total Long-Term Debt	241,660,500	243,680,500	247,867,200	248,617,200	249,367,200		
Total Short-Term Debt	239,997,000	173,483,700	179,799,000	202,016,000	130,339,600		
Total Capital	730,458,535	661,861,411	663,001,138	792,026,786	717,212,450		
Operating Margin (4)	15.32%	17.74%	11.78%	15.80%	18.96%	15.92%	11.78% - 18.96%
Operating Ratio (5)	80.85%	77.98%	82.48%	80.56%	76.94%	79.76%	76.94% - 82.48%
Pre-Tax Earned Return on Total Capital (6)	11.21%	12.59%	8.98%	11.00%	12.23%	11.20%	8.98% - 12.59%
Interally Generated Funds (6)	19.60%	15.75%	12.80%	15.21%	20.14%	16.70%	12.80% - 20.14%
Total Debt / Total Capital	65.94%	63.03%	64.50%	56.90%	52.94%	60.66%	52.94% - 65.94%
Total Equity / Total Capital	34.06%	36.97%	35.50%	43.10%	47.06%	39.34%	34.06% - 47.06%

Notes:
(1) Excluding extraordinary items.
(2) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(3) Includes depereciation and amortization expenses from the Income Statement.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(5) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.

(8) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

Equitable Gas Company

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	666,419,160	458,908,726	445,334,600	471,227,463	420,539,246		
Operating Expenses	632,647,583	448,505,406	360,600,137	407,647,175	356,996,867		
Net Operating Income	33,771,577	10,403,320	84,734,463	63,580,288	63,542,379		
Net Income	24,377,874	257,482,806	220,286,495	260,055,172	279,854,459		
Taxes Other than Income Taxes (1)	3,560,758	2,215,719	3,708,795	2,567,032	3,778,241		
Income Taxes	(2,545,530)	3,169,415	(36,918,432)	(26,843,974)	(29,972,376)		
Provision for Deferred Income Taxes	21,719,223	2,459,979	(13,255,599)	(1,056,489)	4,403,000		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	(5,532)	(9,114)	(19,800)	(24,200)	(29,700)		
Sum of all Taxes	22,728,919	7,835,999	(46,485,036)	(25,357,631)	(21,820,835)		
Cash and Cash Equivalents	27,476	74,105	107,908	80,099,437	2,990,252		
Non-Cash Expenses (2)	22,055,279	20,939,577	20,334,382	19,629,235	17,891,239		
NOI + All Taxes	56,500,496	18,239,319	38,249,427	38,222,657	41,721,544		
Net Income + All Taxes	47,106,793	265,318,805	173,801,459	234,697,541	258,033,624		
All Operating Expenses - Taxes	609,918,664	440,669,407	407,085,173	433,004,806	378,817,702		
Total Proprietary Capital	280,925,338	NMF	NMF	NMF	NMF		
Total Long-Term Debt	181,705,000	NMF	NMF	NMF	NMF		
Total Short-Term Debt	194,126,798	NMF	NMF	NMF	NMF		
Total Capital	656,757,136	NMF	NMF	NMF	NMF		
Operating Margin (3)	8.48%	3.97%	8.59%	8.11%	9.92%	7.81%	3.97% - 9.92%
Operating Ratio (4)	88.21%	91.46%	86.84%	87.72%	85.82%	88.01%	85.82% - 91.46%
Pre-Tax Earned Return on Total Capital (5)	8.60%	NMF	NMF	NMF	NMF	8.60%	8.60%
Interally Generated Funds (6)	10.38%	62.38%	43.59%	53.97%	65.61%	47.19%	10.38% - 65.61%
Total Debt / Total Capital	57.23%	NMF	NMF	NMF	NMF	57.23%	57.23%
Total Equity / Total Capital	42.77%	NMF	NMF	NMF	NMF	42.77%	42.77%

NMF = Not Meaningful as years 2004 - 2007 capitalization was for Equitable Resources, Inc. of which Equitable Gas was a division.

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.

(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

National Fuel Gas Distribution Corporation

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	388,774,706	351,750,102	363,676,070	376,317,451	NMF		
Operating Expenses	359,817,375	324,428,053	347,449,583	360,093,476	NMF		
Net Operating Income	28,957,331	27,322,049	16,226,487	16,223,975	NMF		
Net Income	21,411,060	19,265,979	9,117,573	10,639,936	NMF		
Taxes Other than Income Taxes (1)	653,641	910,184	954,132	657,739	NMF		
Income Taxes	10,299,744	4,825,691	21,673,060	5,529,872	NMF		
Provision for Deferred Income Taxes	11,174,927	8,017,930	(1,009,562)	12,726,310	NMF		
Provision for Deferred Income Taxes - Credit	(8,668,592)	(939,791)	(13,467,919)	(12,575,486)	NMF		
Investment Tax Credit Adjustments	-	-	-	-	NMF		
Sum of all Taxes	13,459,720	12,814,014	8,149,711	6,338,435	NMF		
Cash and Cash Equivalents	18,617,442	13,157,426	23,384,205	15,884,717	NMF		
Non-Cash Expenses (2)	11,153,450	11,586,612	11,284,208	11,217,862	NMF		
NOI + All Taxes	42,417,051	40,136,063	24,376,198	22,562,410	NMF		
Net Income + All Taxes	34,870,780	32,079,993	17,267,284	16,978,371	NMF		
All Operating Expenses - Taxes	346,357,655	311,614,039	339,299,872	353,755,041	NMF		
Total Proprietary Capital	157,876,525	147,310,122	143,521,445	NMF	NMF		
Total Long-Term Debt	80,907,691	51,007,691	71,039,490	NMF	NMF		
Total Short-Term Debt	53,547,909	86,013,209	55,330,449	NMF	NMF		
Total Capital	292,332,125	284,331,022	269,891,384	NMF	NMF		
Operating Margin (3)	10.91%	11.41%	6.70%	6.00%	NMF	8.75%	6.00% - 11.41%
Operating Ratio (4)	86.22%	85.30%	90.19%	91.02%	NMF	88.18%	85.30% - 91.02%
Pre-Tax Earned Return on Total Capital (5)	14.51%	14.12%	9.03%	NMF	NMF	12.55%	9.03% - 14.51%
Interally Generated Funds (6)	11.84%	12.41%	7.85%	7.49%	NMF	9.90%	7.49% - 12.41%
Total Debt / Total Capital	45.99%	48.19%	46.82%	NMF	NMF	47.00%	45.99% - 48.19%
Total Equity / Total Capital	54.01%	51.81%	53.18%	NMF	NMF	53.00%	51.81% - 54.01%

NMF = Not meaningful - 2004 capitalization and operating statistics reported are for National Fuel Gas Company (the Parent) while 2005 operating statistics are for National Fuel Gas Distribution Corp. but capitalization was for the Parent.

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.

(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

PECO Gas

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	821,727,144	838,817,652	795,520,719	816,823,012	747,736,536		
Operating Expenses	779,487,800	782,246,765	752,588,378	758,620,697	692,666,710		
Net Operating Income	42,239,344	56,570,887	42,932,341	58,202,315	55,069,826		
Net Income	325,049,870	506,523,613	440,369,561	516,839,680	455,358,941		
Taxes Other than Income Taxes (1)	3,914,362	3,059,791	1,634,029	316,348	3,782,044		
Income Taxes	5,617,763	20,802,372	26,042,523	5,511,735	8,221,851		
Provision for Deferred Income Taxes	21,504,224	14,490,795	17,711,965	39,413,198	36,003,530		
Provision for Deferred Income Taxes - Credit	(14,242,083)	(13,466,861)	(26,028,710)	(18,246,819)	(14,904,329)		
Investment Tax Credit Adjustments	(566,472)	(566,493)	(566,699)	(566,699)	(566,301)		
Sum of all Taxes	16,227,794	24,319,604	18,793,108	26,427,763	32,536,795		
Cash and Cash Equivalents	22,065,467	24,038,374	21,138,538	25,232,221	43,614,770		
Non-Cash Expenses (2)	33,798,071	31,770,660	34,659,622	39,978,108	36,531,118		
NOI + All Taxes	58,467,138	80,890,491	61,725,449	84,630,078	87,606,621		
Net Income + All Taxes	341,277,664	530,843,217	459,162,669	543,267,443	487,895,736		
All Operating Expenses - Taxes	763,260,006	757,927,161	733,795,270	732,192,934	660,129,915		
Total Proprietary Capital	NMF	NMF	NMF	NMF	NMF		
Total Long-Term Debt	NMF	NMF	NMF	NMF	NMF		
Total Short-Term Debt	NMF	NMF	NMF	NMF	NMF		
Total Capital	NMF	NMF	NMF	NMF	NMF		
Operating Margin (3)	7.12%	9.64%	7.76%	10.36%	11.72%	9.32%	7.12% - 11.72%
Operating Ratio (4)	88.77%	86.57%	87.88%	84.74%	83.40%	86.27%	83.40% - 88.77%
Pre-Tax Earned Return on Total Capital (5)	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Interally Generated Funds (6)	45.64%	67.07%	62.08%	71.40%	70.14%	63.27%	45.64% - 71.40%
Total Debt / Total Capital	NMF	NMF	NMF	NMF	NMF	NMF	NMF
Total Equity / Total Capital	NMF	NMF	NMF	NMF	NMF	NMF	NMF

NMF = Not meaningful - Operating statistics are for PECO gas operations but capitalization is for consolidated PECO which includes electric operations.

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.

(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

T.W. Phillips Gas and Oil Company

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	151,928,908	134,624,031	133,857,036	135,466,453	109,325,578		
Operating Expenses	142,263,572	123,179,369	124,409,295	125,634,270	99,027,423		
Net Operating Income	9,665,336	11,444,662	9,447,741	9,832,183	10,298,155		
Net Income	4,778,650	6,369,898	4,335,118	6,007,880	6,578,066		
Taxes Other than Income Taxes (1)	121,484	106,431	(111,693)	208,783	385,001		
Income Taxes	(1,018,632)	3,777,200	662,183	4,039,259	3,995,000		
Provision for Deferred Income Taxes	4,314,750	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	(34,005)	(33,546)		
Investment Tax Credit Adjustments	(30,205)	(31,844)	(27,026)	-	-		
Sum of all Taxes	3,387,397	3,851,787	523,464	4,214,037	4,346,455		
Cash and Cash Equivalents	(56,384)	(1,575,996)	(1,199,969)	(1,431,311)	(5,244,783)		
Non-Cash Expenses (2)	6,057,585	5,789,107	6,151,130	6,036,092	5,956,333		
NOI + All Taxes	13,052,733	15,296,449	9,971,205	14,046,220	14,644,610		
Net Income + All Taxes	8,166,047	10,221,685	4,858,582	10,221,917	10,924,521		
All Operating Expenses - Taxes	138,876,175	119,327,582	123,885,831	121,420,233	94,680,968		
Total Proprietary Capital	60,981,810	57,088,736	52,851,171	60,001,950	58,357,168		
Total Long-Term Debt	71,841,455	76,364,000	65,432,000	69,500,000	59,000,000		
Total Short-Term Debt	40,974,955	30,378,353	32,993,297	33,500,000	24,000,000		
Total Capital	173,798,220	163,831,089	151,276,468	163,001,950	141,357,168		
Operating Margin (3)	8.59%	11.36%	7.45%	10.37%	13.40%	10.23%	7.45% - 13.40%
Operating Ratio (4)	87.42%	84.34%	87.96%	85.18%	81.16%	85.21%	81.16% - 87.96%
Pre-Tax Earned Return on Total Capital (5)	7.51%	9.34%	6.59%	8.62%	10.36%	8.48%	6.59% - 10.36%
Interally Generated Funds (6)	9.36%	11.89%	8.22%	12.00%	15.44%	11.38%	8.22% - 15.44%
Total Debt / Total Capital	64.91%	65.15%	65.06%	63.19%	58.72%	63.41%	58.72% - 65.15%
Total Equity / Total Capital	35.09%	34.85%	34.94%	36.81%	41.28%	36.59%	34.85% - 41.28%

NMF = Not meaningful - No rational explanation is available from the Company as to how there could be negative cash and cash equivalents on a consistent basis.

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.

(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

UGI Utilities Inc. (Gas)

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	626,347,587	618,389,550	580,617,509	586,670,439	500,491,271		
Operating Expenses	565,964,123	552,524,145	528,282,544	528,373,368	448,498,046		
Net Operating Income	60,383,464	65,865,405	52,334,965	58,297,071	51,993,225		
Net Income	45,848,780	48,527,407	31,837,834	43,290,873	37,208,621		
Taxes Other than Income Taxes (1)	3,251,148	3,007,993	3,963,891	3,657,107	3,332,678		
Income Taxes	32,589,134	23,319,415	22,484,481	17,387,392	16,692,182		
Provision for Deferred Income Taxes	12,763,110	35,595,238	14,216,089	21,968,051	18,248,697		
Provision for Deferred Income Taxes - Credit	(15,079,085)	(28,585,182)	(17,869,644)	(12,831,546)	(10,507,289)		
Investment Tax Credit Adjustments	(318,420)	(318,420)	(318,420)	(318,420)	(318,420)		
Sum of all Taxes	33,205,887	33,019,044	22,476,397	29,862,584	27,447,848		
Cash and Cash Equivalents	37,286,748	17,847,297	13,728,536	2,514,220	1,608,121		
Non-Cash Expenses (2)	22,693,240	22,426,592	22,417,292	21,053,217	19,914,913		
NOI + All Taxes	93,589,351	98,884,449	74,811,362	88,159,655	79,441,073		
Net Income + All Taxes	79,054,667	81,546,451	54,314,231	73,153,457	64,656,469		
All Operating Expenses - Taxes	532,758,236	519,505,101	505,806,147	498,510,784	421,050,198		
Total Proprietary Capital	659,101,702	584,170,693	560,474,431	290,888,640	268,867,429		
Total Long-Term Debt	640,000,000	512,000,000	512,000,000	237,000,000	237,120,600		
Total Short-Term Debt	283,000,000	257,000,000	250,000,000	145,500,000	83,000,000		
Total Capital	1,582,101,702	1,353,170,693	1,322,474,431	673,388,640	588,988,029		
Operating Margin (3)	14.94%	15.99%	12.88%	15.03%	15.87%	14.94%	12.88% - 15.99%
Operating Ratio (4)	81.43%	80.38%	83.25%	81.38%	80.15%	81.32%	80.15% - 83.25%
Pre-Tax Earned Return on Total Capital (5)	5.92%	7.31%	5.66%	13.09%	13.49%	9.09%	5.66% - 13.49%
Interally Generated Funds (6)	16.24%	16.81%	13.22%	16.06%	16.90%	15.85%	13.22% - 16.90%
Total Debt / Total Capital	58.34%	56.83%	57.62%	56.80%	54.35%	56.79%	54.35% - 58.34%
Total Equity / Total Capital	41.66%	43.17%	42.38%	43.20%	45.65%	43.21%	41.66% - 45.65%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company submitted Annual Reports to the Pennsylvania Public Utility Commission

Proxy Group of Seven Pennsylvania Natural Gas Distribution Companies
Selection Criteria
2004-2008, Inclusive

Selection Criteria:

The basis of selection was to include those natural gas distribution companies: 1) Which were regulated by the Pennsylvania Public Utility Commission (PAPUC); 2) Which had over $40 million in revenues in 2008; and 3) Had available PAPUC annual reports for the years 2004 – 2008 from the PAPUC website.

The following seven natural gas distribution companies met the above criteria:

Columbia Gas of Pennsylvania
Equitable Gas Company
National Fuel Gas Distribution Corp.
UGI Utilities Inc. (Gas)
Dominion Peoples
Exelon Corporation (PECO Gas)
T.W. Phillips Gas & Oil Company

Source of Information: PAPUC Annual Reports
http://www.puc.state.pa.us

Proxy Group of Seven Value Line Natural Gas Distribution Companies

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,875,739,714	2,565,229,429	2,624,479,286	2,265,788,571	1,686,623,286		
Operating Expenses	2,669,375,339	2,376,300,286	2,443,163,571	2,100,751,000	1,553,089,714		
Net Operating Income	206,364,375	188,929,143	181,315,714	165,037,571	133,533,571		
Net Income	120,422,714	116,229,143	107,522,143	97,858,857	83,573,857		
Taxes Other than Income Taxes (1)	72,133,143	69,642,571	70,252,714	58,580,714	41,069,714		
Income Taxes	69,197,286	65,631,000	62,043,857	55,978,286	47,099,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	141,330,429	135,273,571	132,296,571	114,559,000	88,168,714		
Cash and Cash Equivalents	17,726,571	26,422,000	26,340,286	29,391,143	42,276,857		
Non-Cash Expenses (2)	120,250,143	115,294,143	110,092,857	103,852,429	85,029,571		
NOI + All Taxes	347,694,804	324,202,714	313,612,286	279,596,571	221,702,286		
Net Income + All Taxes	261,753,143	251,502,714	239,818,714	212,417,857	171,742,571		
All Operating Expenses - Taxes	2,528,044,910	2,241,026,714	2,310,867,000	1,986,192,000	1,464,921,000		
Total Proprietary Capital	1,117,233,286	1,074,492,000	999,199,571	944,759,714	840,881,429		
Total Long-Term Debt	1,070,602,571	1,083,339,143	1,089,097,143	1,059,106,714	856,898,143		
Total Short-Term Debt	344,699,571	210,549,429	225,170,286	155,355,714	116,144,857		
Total Capital	2,532,535,429	2,368,380,571	2,313,467,000	2,159,222,143	1,813,924,429		
Operating Margin (3)	12.09%	12.64%	11.95%	12.34%	13.14%	12.43%	12.09% - 13.14%
Operating Ratio (4)	83.73%	82.87%	83.86%	83.08%	81.81%	83.07%	81.81% - 83.86%
Pre-Tax Earned Return on Total Capital (5)	13.73%	13.69%	13.56%	12.95%	12.22%	13.23%	12.22% - 13.73%
Interally Generated Funds (6)	13.28%	14.30%	13.33%	13.96%	15.22%	14.02%	13.28% - 15.22%
Total Debt / Total Capital	55.88%	54.63%	56.81%	56.25%	53.64%	55.44%	53.64% - 56.81%
Total Equity / Total Capital	44.12%	45.37%	43.19%	43.75%	46.36%	44.56%	43.19% - 46.36%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

AGL Resources, Inc.

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,800,000,000	2,494,000,000	2,621,000,000	2,718,000,000	1,832,000,000		
Operating Expenses	2,454,000,000	2,132,000,000	2,262,000,000	2,393,000,000	1,590,000,000		
Net Operating Income	346,000,000	362,000,000	359,000,000	325,000,000	242,000,000		
Net Income	217,000,000	211,000,000	212,000,000	193,000,000	153,000,000		
Taxes Other than Income Taxes (1)	44,000,000	41,000,000	40,000,000	40,000,000	30,000,000		
Income Taxes	132,000,000	127,000,000	129,000,000	117,000,000	90,000,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	176,000,000	168,000,000	169,000,000	157,000,000	120,000,000		
Cash and Cash Equivalents	16,000,000	21,000,000	20,000,000	30,000,000	49,000,000		
Non-Cash Expenses (2)	152,000,000	144,000,000	138,000,000	133,000,000	99,000,000		
NOI + All Taxes	522,000,000	530,000,000	528,000,000	482,000,000	362,000,000		
Net Income + All Taxes	393,000,000	379,000,000	381,000,000	350,000,000	273,000,000		
All Operating Expenses - Taxes	2,278,000,000	1,964,000,000	2,093,000,000	2,236,000,000	1,470,000,000		
Total Proprietary Capital	1,652,000,000	1,661,000,000	1,609,000,000	1,499,000,000	1,385,000,000		
Total Long-Term Debt	1,675,000,000	1,674,000,000	1,622,000,000	1,615,000,000	1,623,000,000		
Total Short-Term Debt	866,000,000	580,000,000	539,000,000	522,000,000	334,000,000		
Total Capital	4,193,000,000	3,915,000,000	3,770,000,000	3,636,000,000	3,342,000,000		
Operating Margin (3)	18.64%	21.25%	20.14%	17.73%	19.76%	19.51%	17.73% - 21.25%
Operating Ratio (4)	75.93%	72.98%	74.59%	77.37%	74.84%	75.14%	72.98% - 77.37%
Pre-Tax Earned Return on Total Capital (5)	12.45%	13.54%	14.01%	13.26%	10.83%	12.82%	10.83% - 14.01%
Interally Generated Funds (6)	19.46%	20.97%	19.80%	17.77%	20.31%	19.66%	17.77% - 20.97%
Total Debt / Total Capital	60.60%	57.57%	57.32%	58.77%	58.56%	58.57%	57.32% - 60.60%
Total Equity / Total Capital	39.40%	42.43%	42.68%	41.23%	41.44%	41.43%	39.40% - 42.68%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Atmos Energy Corp.

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	7,221,305,000	5,898,431,000	6,152,363,000	4,973,326,000	2,920,037,000		
Operating Expenses	6,793,522,373	5,593,887,000	5,858,900,000	4,706,904,000	2,777,880,000		
Net Operating Income	427,782,627	304,544,000	293,463,000	266,422,000	142,157,000		
Net Income	180,331,000	168,492,000	147,737,000	135,785,000	86,227,000		
Taxes Other than Income Taxes (1)	192,755,000	182,866,000	191,993,000	174,696,000	57,379,000		
Income Taxes	112,373,000	94,092,000	89,153,000	82,233,000	51,538,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	305,128,000	276,958,000	281,146,000	256,929,000	108,917,000		
Cash and Cash Equivalents	46,717,000	60,725,000	75,815,000	121,072,000	201,932,000		
Non-Cash Expenses (2)	200,442,000	198,863,000	185,596,000	178,005,000	96,647,000		
NOI + All Taxes	732,910,627	581,502,000	574,609,000	523,351,000	251,074,000		
Net Income + All Taxes	485,459,000	445,450,000	428,883,000	392,714,000	195,144,000		
All Operating Expenses - Taxes	6,488,394,373	5,316,929,000	5,577,754,000	4,449,975,000	2,668,963,000		
Total Proprietary Capital	2,052,492,000	1,965,754,000	1,648,098,000	1,602,422,000	1,133,459,000		
Total Long-Term Debt	2,120,577,000	2,130,146,000	2,183,548,000	2,186,368,000	867,219,000		
Total Short-Term Debt	350,542,000	150,599,000	382,416,000	144,809,000	-		
Total Capital	4,523,611,000	4,246,499,000	4,214,062,000	3,933,599,000	2,000,678,000		
Operating Margin (3)	10.15%	9.86%	9.34%	10.52%	8.60%	9.69%	8.60% - 10.52%
Operating Ratio (4)	87.08%	86.77%	87.64%	85.90%	88.09%	87.10%	85.90% - 88.09%
Pre-Tax Earned Return on Total Capital (5)	16.20%	13.69%	13.64%	13.30%	12.55%	13.88%	12.55% - 16.20%
Interally Generated Funds (6)	9.50%	10.92%	9.99%	11.48%	9.99%	10.38%	9.50% - 11.48%
Total Debt / Total Capital	54.63%	53.71%	60.89%	59.26%	43.35%	54.37%	43.35% - 60.89%
Total Equity / Total Capital	45.37%	46.29%	39.11%	40.74%	56.65%	45.63%	39.11% - 56.65%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Laclede Group, Inc.

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,208,973,000	2,021,594,000	1,997,551,000	1,597,032,000	1,250,320,000		
Operating Expenses	2,123,816,000	1,941,363,000	1,917,843,000	1,527,964,000	1,189,023,000		
Net Operating Income	85,157,000	80,231,000	79,708,000	69,068,000	61,297,000		
Net Income	77,922,000	49,771,000	48,989,000	40,070,000	36,056,000		
Taxes Other than Income Taxes (1)	69,023,000	68,361,000	71,038,000	62,859,000	60,077,000		
Income Taxes	26,190,000	25,035,000	23,567,000	20,761,000	19,264,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	95,213,000	93,396,000	94,605,000	83,620,000	79,341,000		
Cash and Cash Equivalents	14,899,000	52,746,000	50,778,000	6,013,000	13,854,000		
Non-Cash Expenses (2)	35,303,000	34,080,000	30,904,000	23,036,000	22,385,000		
NOI + All Taxes	180,370,000	173,627,000	174,313,000	152,688,000	140,638,000		
Net Income + All Taxes	173,135,000	143,167,000	143,594,000	123,690,000	115,397,000		
All Operating Expenses - Taxes	2,028,603,000	1,847,967,000	1,823,238,000	1,444,344,000	1,109,682,000		
Total Proprietary Capital	486,946,000	428,952,000	403,424,000	367,473,000	357,023,000		
Total Long-Term Debt	389,341,000	395,682,000	395,600,000	380,494,000	405,481,000		
Total Short-Term Debt	215,900,000	211,400,000	207,300,000	70,605,000	71,380,000		
Total Capital	1,092,187,000	1,036,034,000	1,006,324,000	818,572,000	833,884,000		
Operating Margin (3)	8.17%	8.59%	8.73%	9.56%	11.25%	9.26%	12.88% - 15.99%
Operating Ratio (4)	90.24%	89.73%	89.73%	89.00%	86.96%	89.13%	80.15% - 83.25%
Pre-Tax Earned Return on Total Capital (5)	16.51%	16.76%	17.32%	18.65%	16.87%	17.22%	5.66% - 13.49%
Interally Generated Funds (6)	9.44%	8.77%	8.74%	9.19%	11.02%	9.43%	13.22% - 16.90%
Total Debt / Total Capital	55.42%	58.60%	59.91%	55.11%	57.19%	57.24%	55.11% - 59.91%
Total Equity / Total Capital	44.58%	41.40%	40.09%	44.89%	42.81%	42.76%	40.09% - 44.89%

Notes:
(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Northwest Natural Gas Company

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	1,037,855,000	1,033,193,000	1,013,172,000	910,486,000	707,604,000		
Operating Expenses	934,497,000	922,330,000	912,644,000	816,259,000	624,109,000		
Net Operating Income	103,358,000	110,863,000	100,528,000	94,227,000	83,495,000		
Net Income	69,525,000	74,497,000	63,415,000	58,149,000	50,572,000		
Taxes Other than Income Taxes (1)	26,660,000	25,288,000	24,419,000	23,185,000	38,808,000		
Income Taxes	40,678,000	44,060,000	36,234,000	32,720,000	26,531,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	67,338,000	69,348,000	60,653,000	55,905,000	65,339,000		
Cash and Cash Equivalents	6,916,000	6,107,000	5,767,000	7,143,000	5,248,000		
Non-Cash Expenses (2)	72,159,000	68,343,000	64,435,000	61,645,000	57,371,000		
NOI + All Taxes	170,696,000	180,211,000	161,181,000	150,132,000	148,834,000		
Net Income + All Taxes	136,863,000	143,845,000	124,068,000	114,054,000	115,911,000		
All Operating Expenses - Taxes	867,159,000	852,982,000	851,991,000	760,354,000	558,770,000		
Total Proprietary Capital	628,373,000	594,751,000	599,545,000	586,931,000	568,517,000		
Total Long-Term Debt	512,000,000	517,000,000	546,500,000	529,500,000	499,027,000		
Total Short-Term Debt	248,000,000	143,100,000	100,100,000	126,700,000	102,500,000		
Total Capital	1,388,373,000	1,254,851,000	1,246,145,000	1,243,131,000	1,170,044,000		
Operating Margin (3)	16.45%	17.44%	15.91%	16.49%	21.03%	17.46%	15.91% - 21.03%
Operating Ratio (4)	76.60%	75.94%	77.73%	76.74%	70.86%	75.57%	70.86% - 77.73%
Pre-Tax Earned Return on Total Capital (5)	12.29%	14.36%	12.93%	12.08%	12.72%	12.88%	12.08% - 14.36%
Interally Generated Funds (6)	20.14%	20.54%	18.61%	19.30%	24.49%	20.61%	18.61% - 24.49%
Total Debt / Total Capital	54.74%	52.60%	51.89%	52.79%	51.41%	52.69%	51.41% - 54.74%
Total Equity / Total Capital	45.26%	47.40%	48.11%	47.21%	48.59%	47.31%	45.26% - 48.59%

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Piedmont Natural Gas Company, Inc.

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,089,108,000	1,711,292,000	1,924,628,000	1,761,091,000	1,529,739,000		
Operating Expenses	1,935,997,000	1,573,945,000	1,793,879,000	1,635,791,000	1,402,424,000		
Net Operating Income	153,111,000	137,347,000	130,749,000	125,300,000	127,315,000		
Net Income (1)	120,685,000	118,698,000	109,076,000	111,716,000	105,750,000		
Taxes Other than Income Taxes (2)	33,170,000	32,407,000	33,138,000	29,807,000	27,011,000		
Income Taxes	62,814,000	51,315,000	50,543,000	51,880,000	51,485,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	95,984,000	83,722,000	83,681,000	81,687,000	78,496,000		
Cash and Cash Equivalents	6,991,000	7,515,000	8,886,000	7,065,000	5,676,000		
Non-Cash Expenses (3)	93,121,000	88,654,000	89,696,000	85,169,000	82,276,000		
NOI + All Taxes	249,095,000	221,069,000	214,430,000	206,987,000	205,811,000		
Net Income + All Taxes	216,669,000	202,420,000	192,757,000	193,403,000	184,246,000		
All Operating Expenses - Taxes	1,840,013,000	1,490,223,000	1,710,198,000	1,554,104,000	1,323,928,000		
Total Proprietary Capital	887,244,000	878,374,000	882,925,000	884,192,000	854,898,000		
Total Long-Term Debt	824,261,000	824,887,000	825,000,000	660,000,000	660,000,000		
Total Short-Term Debt	406,500,000	195,500,000	170,000,000	158,500,000	109,500,000		
Total Capital	2,118,005,000	1,898,761,000	1,877,925,000	1,702,692,000	1,624,398,000		
Operating Margin (4)	11.92%	12.92%	11.14%	11.75%	13.45%	12.24%	11.14% - 13.45%
Operating Ratio (5)	83.62%	81.90%	84.20%	83.41%	81.17%	82.86%	81.17% - 84.20%
Pre-Tax Earned Return on Total Capital (6)	11.76%	11.64%	11.42%	12.16%	12.67%	11.93%	11.42% - 12.67%
Interally Generated Funds (7)	14.83%	17.01%	14.68%	15.82%	17.42%	15.95%	14.68% - 17.42%
Total Debt / Total Capital	58.11%	53.74%	52.98%	48.07%	47.37%	52.06%	47.37% - 58.11%
Total Equity / Total Capital	41.89%	46.26%	47.02%	51.93%	52.63%	47.94%	41.89% - 52.63%

Notes:
(1) Excluding Income tax on other income (below the line income tax expense).
(2) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(3) Includes depereciation and amortization expenses from the Income Statement.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(5) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Southwest Gas Corporation

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,144,743,000	2,152,088,000	2,024,758,000	1,714,283,000	1,477,060,000		
Operating Expenses	1,977,716,000	1,979,279,000	1,860,073,000	1,588,247,000	1,337,530,000		
Net Operating Income	167,027,000	172,809,000	164,685,000	126,036,000	139,530,000		
Net Income	60,973,000	83,246,000	83,860,000	43,823,000	56,775,000		
Taxes Other than Income Taxes (1)	36,780,000	37,553,000	34,994,000	39,040,000	37,669,000		
Income Taxes	40,835,000	47,778,000	44,497,000	24,612,000	30,237,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	77,615,000	85,331,000	79,491,000	63,652,000	67,906,000		
Cash and Cash Equivalents	26,399,000	31,991,000	18,786,000	29,603,000	13,641,000		
Non-Cash Expenses (2)	193,719,000	182,514,000	168,964,000	156,253,000	146,018,000		
NOI + All Taxes	244,642,000	258,140,000	244,176,000	189,688,000	207,436,000		
Net Income + All Taxes	138,588,000	168,577,000	163,351,000	107,475,000	124,681,000		
All Operating Expenses - Taxes	1,900,101,000	1,893,948,000	1,780,582,000	1,524,595,000	1,269,624,000		
Total Proprietary Capital	1,037,841,000	983,673,000	901,425,000	751,135,000	705,676,000		
Total Long-Term Debt	1,293,307,000	1,404,146,000	1,413,899,000	1,408,113,000	1,292,757,000		
Total Short-Term Debt	55,000,000	9,000,000	-	24,000,000	100,000,000		
Total Capital	2,386,148,000	2,396,819,000	2,315,324,000	2,183,248,000	2,098,433,000		
Operating Margin (3)	11.41%	11.99%	12.06%	11.07%	14.04%	12.11%	11.07% - 14.04%
Operating Ratio (4)	79.56%	79.52%	79.60%	79.82%	76.07%	78.91%	76.07% - 79.82%
Pre-Tax Earned Return on Total Capital (5)	10.25%	10.77%	10.55%	8.69%	9.89%	10.03%	8.69% - 10.77%
Interally Generated Funds (6)	15.49%	16.31%	16.41%	15.38%	18.33%	16.39%	15.38% - 18.33%
Total Debt / Total Capital	56.51%	58.96%	61.07%	65.60%	66.37%	61.70%	56.51% - 66.37%
Total Equity / Total Capital	43.49%	41.04%	38.93%	34.40%	33.63%	38.30%	33.63% - 43.49%

Notes:

(1) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(2) Includes depereciation and amortization expenses from the Income Statement.
(3) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(4) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(5) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

WGL Holdings, Inc.

	2008	2007	2006	2005	2004	Five-Year Average	Range
Operating Revenues	2,628,194,000	2,646,008,000	2,637,883,000	2,186,302,000	2,089,603,000		
Operating Expenses	2,466,079,000	2,491,298,000	2,496,806,000	2,037,092,000	1,950,662,000		
Net Operating Income	162,115,000	154,710,000	141,077,000	149,210,000	138,941,000		
Net Income	116,523,000	107,900,000	87,578,000	102,469,000 (1)	96,637,000		
Taxes Other than Income Taxes (2)	102,544,000	100,023,000	96,187,000	40,478,000	36,544,000		
Income Taxes	69,491,000	70,137,000	61,313,000	62,642,000	60,638,000		
Provision for Deferred Income Taxes	-	-	-	-	-		
Provision for Deferred Income Taxes - Credit	-	-	-	-	-		
Investment Tax Credit Adjustments	-	-	-	-	-		
Sum of all Taxes	172,035,000	170,160,000	157,500,000	103,120,000	97,182,000		
Cash and Cash Equivalents	6,164,000	4,870,000	4,350,000	4,842,000	6,587,000		
Non-Cash Expenses (3)	95,007,000	90,605,000	93,055,000	89,859,000	91,510,000		
NOI + All Taxes	334,150,000	324,870,000	298,577,000	252,330,000	236,123,000		
Net Income + All Taxes	288,558,000	278,060,000	245,078,000	205,589,000	193,819,000		
All Operating Expenses - Taxes	2,294,044,000	2,321,138,000	2,339,306,000	1,933,972,000	1,853,480,000		
Total Proprietary Capital	1,075,737,000	1,008,940,000	949,980,000	922,165,000	881,597,000		
Total Long-Term Debt	679,732,000	637,513,000	637,133,000	634,272,000	650,803,000		
Total Short-Term Debt	270,955,000	184,247,000	177,376,000	40,876,000	95,634,000		
Total Capital	2,026,424,000	1,830,700,000	1,764,489,000	1,597,313,000	1,628,034,000		
Operating Margin (4)	12.71%	12.28%	11.32%	11.54%	11.30%	11.83%	11.30% - 12.71%
Operating Ratio (5)	83.67%	84.30%	85.15%	84.35%	84.32%	84.36%	83.67% - 85.15%
Pre-Tax Earned Return on Total Capital (6)	16.49%	17.75%	16.92%	15.80%	14.50%	16.29%	14.50% - 17.75%
Interally Generated Funds (7)	14.59%	13.93%	12.82%	13.51%	13.65%	13.70%	12.82% - 14.59%
Total Debt / Total Capital	46.91%	44.89%	46.16%	42.27%	45.85%	45.22%	42.27% - 46.91%
Total Equity / Total Capital	53.09%	55.11%	53.84%	57.73%	54.15%	54.78%	53.09% - 57.73%

Notes:
(1) Excluding income tax on other income (below the line income tax expense).
(2) Excluding payroll taxes i.e. Social Security tax, Unemployment tax, and Sales tax.
(3) Includes depereciation and amortization expenses from the Income Statement.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(5) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(6) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(7) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.

Source of Information: Company SEC Forms 10-K

Proxy Group of Seven Value Line Natural Gas Distribution Companies
Selection Criteria
2004-2008, Inclusive

Selection Criteria:

The basis of selection was to include those natural gas distribution companies: 1) which are included in the Natural Gas (Utility) group in Value Line (Standard Edition); 2) which have Value Line five-year earnings per share growth rate projections; 3) which have positive Value Line five-year growth rate projections for dividends per share 4) which have a Value Line beta; 5) which have not cut or omitted their common dividends during the five years ending 2008 or through the time of the preparation of this testimony; 6) which derived 60% or greater of both total net operating income and assets from regulated gas operations; and 7) which at the time of the preparation of this testimony, had not publicly announced that they were involved in any merger or acquisition activity.

The following seven natural gas distribution companies met the above criteria:

AGL Resources, Inc.
The Laclede Group, Inc.
Piedmont Natural Gas Co., Inc.
WGL Holdings, Inc.
Atmos Energy Corp.
Northwest Natural Gas Co.
Southwest Gas Corporation

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus / Research Insight Database
EDGAR Online's I-Metrix Database
Company Annual Forms 10K

Exhibit FJH-1
Schedule 6

Philadelphia Gas Works

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
	PGW Average 2004 - 2008	Budget 2009-2010 (1)	Adjusted Budget 2009-2010 (1)	Five Year Average 2004 - 2008 of the Six Next Largest Municipal Gas Systems	Five Year Average 2004 - 2008 of the Seven PA Natural Gas Ditribution Companies	Five Year Average 2004 - 2008 of the Seven Value Line Natural Gas Distribution Companies
Operating Revenues		839,409,000	882,864,000			
Operating Expenses		736,879,000	737,890,000			
Net Operating Income		102,530,000	144,974,000			
Net Income		42,550,000	79,731,000			
Cash and Cash Equivalents		50,201,000	51,949,000			
Depreciation and Amortization		40,409,000	40,409,000			
Funds Available for Debt Service		195,146,000	196,772,000			
Total Annual Debt Service		110,878,409	120,719,018			
Total Proprietary Capital		286,011,000	323,192,000			
Total Long-Term Debt		1,115,372,000	1,262,496,000			
Total Short-Term Debt		5,000,000	-			
Total Capital		1,406,383,000	1,585,688,000			
Operating Margin (2)	7.21%	12.21%	NMF	12.48%	10.89%	12.43%
Operating Ratio (3)	88.19%	82.97%	NMF	77.24%	85.26%	83.07%
Pre-Tax Earned Return on Total Capital (4)	4.45%	7.29%	NMF	4.89%	10.43%	13.23%
Days Cash (5)	12.07	26.31	27.19	131.13	N/A	N/A
Interally Generated Funds (6)	5.34%	9.88%	NMF	11.93%	29.74%	14.02%
Total Debt / Total Capital	84.22%	79.66%	79.62%	54.28%	55.30%	55.44%
Total Equity / Total Capital	15.78%	20.34%	20.38%	45.72%	44.70%	44.56%
Debt Service Coverage (7) (times)	1.23	1.76	1.63	10.06	N/A	N/A
Debt Service Coverage Including $18 M City Fee (times)	1.04	1.49	1.40	N/A	N/A	N/A

N/A = Not Applicable

NMF = Not meaningful as all of the additional revenues requested are to fund PGW's OPEB liability. As such, the funds will be placed into trust and will not be available as a source of cash for such ratios.

Notes:
(1) PGW provided.
(2) Calculated by dividing net operating income + all taxes (excluding payroll) by total operating revenue.
(3) Calculated by dividing all operating expenses minus taxes and non-cash expenses by total operating revenues.
(4) Calculated by dividing net operating income + all taxes (excluding payroll) by total capital.
(5) Calculated by dividing cash and equivalents by daily operating expense minus non-payroll taxes and non-cash expenses.
(6) Calculated by dividing net income plus non-payroll taxes and non-cash expenses by total operating revenues.
(7) Calculated by dividing the funds available for debt service by the total annual debt service.

Source of Information: Schedules 1, 2, 4, and 5 of this Exhibit.

TAB

10

PGW St. No. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

JOHN J. PLUNKETT
GREEN ENERGY ECONOMICS GROUP, INC.

ON BEHALF OF
PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

DECEMBER 2009

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification & Qualifications

Q: State your name, occupation, and business address.

A: I am John J. Plunkett. I am a partner in and president of Green Energy Economics Group, Inc., a small energy consultancy I co-founded in 2005. My office address is 1002 Jerusalem Road, Bristol Vermont 05443.

Q: Summarize your qualifications.

A: My resume is attached as Exhibit JJP-1.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. I have testified over two dozen times before utility regulators in a dozen states and three Canadian provinces.

Q: Have you testified previously before the Pennsylvania Public Utility Commission (PUC)?

A: Yes, on several occasions since 1985. In 2006 I submitted written direct and surrebuttal testimony for Citizens for Pennsylvania's Future (Pennfuture) on appropriate levels of electric DSM investment in Docket Nos. 00061366 and 00061367 re Metropolitan Edison Company and Pennsylvania Electric Company; and Docket No. R-00061346 re Duquesne Light Company. In 2005 I submitted testimony on behalf of PennFuture regarding Energy-Efficiency portfolio investment in the Exelon merger proceeding in Docket No. A-110550F0160.

In 1985, I testified as an expert witness on behalf of Office of Consumer Advocate ("OCA") on the potential for energy efficiency to provide an economical alternative to completing and operating the second unit of the Limerick nuclear power station.

Q: Describe your work on energy efficiency and conservation investment plans in the United States over the last ten years.

A: I have been involved in the review or preparation of many gas and electricity demand-side management investment plans over the past two decades. In 2008-9, I testified in two proceedings before the British Columbia Utilities Commission concerning the proposed DSM program plans filed (separately) by Terasen Gas and BC Hydro.

I am in my second year working for People's Gas, a natural gas utility serving the city of Chicago and its suburbs, on economic analysis in the planning and implementation of its Chicagoland three-year energy efficiency program portfolio. Since 2007 I have been working for New York City's Economic Development Corporation on three parallel assignments, including the Public Service Commission's Energy Efficiency Portfolio proceeding to establish programs for Consolidated Edison's customers to reduce by 15% the forecasted electricity and gas requirements for 2015. I have also assisted the city in collaborative negotiations concerning Consolidated Edison's gas DSM programs for 2009-2010, and in the design and evaluation of its geographically targeted electric DSM program to defer transmission and distribution (T&D) investment.

Since its inception in 2000, I have been engaged as a senior advisor for Efficiency Vermont, the nation's first statewide "energy-efficiency utility." I helped to establish performance goals for three, three-year contracts with the Public Service Board. In the 2009-2011 contract, portfolio investment will approach $40 million annually, placing Vermont, for its size, at the forefront of energy-efficiency investment in North America. My most recent assignment was to lead a team to forecast economically achievable peak demand and energy savings from continued efficiency investment for twenty more years.

Q: What experience do you have with energy efficiency and conservation investment in China?

A: I have consulted on energy efficiency and conservation at the national and provincial levels in China for several non-governmental organizations since 2003. Since 2007, I have provided technical support on the economic and financial assessment of energy efficiency and conservation investment projects in Guangdong Province for the Montpelier, Vermont-based Institute for Sustainable Communities. In that effort, I am currently working with Chinese experts to train and technically support citizen groups in the economic and financial analysis of community scale efficiency and renewable projects in three cities in Guangdong.

For the Asian Development Bank in 2006-2007, I led a team of Chinese and American experts in a pre-feasibility study of a 24-year, $120 million loan to Guangdong Province to establish a revolving financing facility for industrial and commercial / institutional efficiency retrofit investments. This analysis included technical, economic, and financial analysis of the "efficiency power plant" portfolio, and of case studies of ten "subprojects." ADB's Board of Directors unanimously approved the loan in June 2008.

From July 2003 through 2007, I was the consulting team leader for the Natural Resources Defense Council on the development, assessment, and implementation of Chinese demand side management investment portfolios. I led the modification and application of U.S.-based program and portfolio economic analysis tools for DSM planning in Jiangsu Province. There I assisted with the design and planning for first-stage implementation of DSM programs investing $12 million annually on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling. I provided training and technical support on economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers in 2007 and 2008.

I was on the consulting team that drafted a national DSM implementation manual last year, sponsored by the PRC's National Development and Reform Commission. Working with California's investor-owned utilities and American and Chinese experts, I wrote chapters concerning performance indicators and cost-effectiveness analysis. The Chinese central government approved and issued the national DSM manual in April 2008.

Q: Have you done any other work related to demand-side management investment in Pennsylvania?

A: Yes. In 2007 I prepared a report for Pennfuture examining the potential for expanded DSM investment to offset growth in long-term electricity requirements. I found that by following in the footsteps of leading DSM program administrators in California and Vermont, Pennsylvania could cost-effectively eliminate growth in electricity supply requirements.

In 2005, also on behalf of Pennfuture, I led a consulting team that recommended protocols ultimately adopted by the Commission for certifying compliance with PUC rulemaking to implement energy-efficiency provisions of an alternative energy portfolio standard.

In 1997, I was the lead author of a business plan for an all-energy consumer-owned cooperative to serve Philadelphia and Pittsburgh, prepared on behalf of the Energy Coordinating Agency of Philadelphia and other non-government organizations.

From 1991 to 1993, I provided technical support to the Pennsylvania Energy Office in its evaluation of Pennsylvania electric utility demand-management plans. With Paul Chernick, I co-authored a comprehensive, study of all aspects of demand management planning and regulation. This five-volume report, entitled "From Here to Efficiency," surveyed such core DSM issues as program design, cost-recovery mechanisms, and cost-effectiveness assessment. I still use this material for training purposes in assignments elsewhere.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Philadelphia Gas Works (PGW).

Q: What is the purpose of your testimony?

A: The purpose of my testimony is fourfold: first, to explain why in my opinion it is important that PGW have an appropriately structured and reasonably sized DSM plan; second, to describe the DSM program portfolio that PGW proposes to implement over the next five years; third, to present the program expenditures and gas savings planned for each year, and the supporting calculation of benefits and costs to PGW's customers and its overall economy over the lifetime of all the measures installed as a result of implementing the portfolio; and fourth, to demonstrate that the programs PGW proposes follow best industry design and implementation practices.

Q: Summarize your testimony.

A: In Section III, I explain why PGW's proposed DSM portfolio is consistent with government policy to conserve natural resources, to reduce carbon emissions and to use energy in the most efficient manner possible. In Section IV, I describe the 7 programs PGW proposes to implement as part of its five-year $54 million demand-side management portfolio. In Section V, I explain the portfolio's annual budgets, gas savings and strategy. In Section VI, I describe the benefits and costs of the portfolio.

PGW plans to unveil the portfolio, upon PUC approval, in three phases starting in September 2010, or sooner if allowed to do so. Building on the success of PGW's existing low-income program, the portfolio starts by enhancing the comprehensiveness of efficiency treatment and increasing the number of customers treated. In 2010, PGW also plans to work with other City government institutions on a five-year campaign to invest in cost-effective efficiency retrofits of all municipal facilities.

During the second stage of program implementation, PGW will expand availability of whole-house efficiency services to the rest of Philadelphia's residential customers in 2011.[1] PGW will also introduce financial incentives to increase penetration of high-efficiency technologies in markets in which gas-using heating and other equipment is routinely bought and sold.

In 2012, PGW will introduce financial incentives and other assistance to improve building and equipment efficiency in residential and commercial construction and renovation. The third phase of portfolio implementation will also include incentives and services to encourage gas efficiency retrofits to existing commercial facilities.

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[1] I am informed by PGW that PGW will make all efforts to begin implementation of programs earlier if allowed to do so by the Commission.

Throughout the five year period covered by the DSM Plan, PGW will work with other market participants to integrate gas efficiency with electricity, water, and other efficiency investments to minimize costs and maximize benefits from program implementation.

These investments will require outlays on the part of PGW ranging from $0.35 to $15.7 million annually. PGW will administer these programs by continuing its successful practice of managing outside contractors to deliver services meeting exacting quality standards. PGW will meet the increased management responsibilities associated with expanding its DSM portfolio through a combination of seasoned senior staff, modest levels of additional staffing, and a few specialized consultants to help PGW specify, plan, direct, oversee, report on, and evaluate the work of independent program implementation contractors. PGW plans to continue the current practice of regular, independent audits of the program.

From this cumulative investment of $54 million, PGW expects to reduce consumption by 2.64 million therms per year. Including participating customers' direct investment in efficiency measures promoted by PGW's programs, total program investment over five years is estimated at $58 million in present worth. The benefits of these savings are valued at $113 million over the life expectancy of all the efficiency measures installed through the programs. Benefits are valued at the avoided costs of gas supply to PGW for meeting customer requirements, as discussed in the testimony of PGW witness Chernick.

The net economic benefits to Philadelphia Gas customers are valued at $55 million, above and beyond PGW and customer costs. These cost savings in turn increase the amount of discretionary income available to City households, which they are free to spend and/or save as they see fit.

Business customers likewise will enjoy lower operating costs, which will increase profitability. Lower operating costs for City-owned and -managed properties will help ease the burden on the City's residential and business taxpayers as well as reducing the City's operating budget.

The additional income afforded City households and businesses by gas bill savings by PGW programs will further stimulate economic activity as customers spend more on goods and services, some of which will be provided in whole or in part with local labor and other resources. This economic stimulus is an indirect job-producing benefit from lowering gas bills with cost-effective DSM investment and is likely to be several times larger than the direct net benefit created by the PGW DSM portfolio

III. Justification for PGW Gas Conservation Programs

Q. Why is it appropriate for PGW to implement a Demand-Side Management energy efficiency and conservation plan?

A: Improving efficiency in all the end uses of our energy resources is the cornerstone of this nation's energy, economic, and environmental policy goals. In Pennsylvania, the General Assembly has embraced this view by the passage of Act 129 of 2008 which mandates, among other things, the implementation of electric distribution company programs, funded by ratepayers, to promote energy conservation and efficiency improvements. I can think of no valid reason why the Act's mandate for utility distribution company conservation programs should not also apply to natural gas utilities with equal force. Over 30 years of program experience across North America proves that large-scale energy efficiency and conservation investment portfolios can be efficiently and cost-effectively administered by the distribution utilities responsible for delivering energy service.

Q. Is it particularly important for PGW to implement a DSM plan in comparison to other natural gas utilities?

A: Yes. Such a plan makes particular sense for PGW for several reasons. Its rates are higher than the average for other Pennsylvania natural gas utilities. Compared to other gas utilities in the Commonwealth, it has a higher proportion of residential customers, a higher proportion of whom has low incomes. Moreover, PGW has had a successful low-income energy conservation program for some years. This particular experience puts PGW in an especially strong position to implement the proposed plan.

Q. Will PGW's plan, if implemented, benefit its customers?

A. Yes, significantly. In the narrative description of PGW's plan, which is Exhibit JJP-6 to my testimony, I describe the plan's goals and objectives:

PGW's DSM plan has five broad goals:

- Reduce customer bills;
- Maximize customer value;
- Contribute to the fulfillment of the City's sustainability plan;
- Reduce PGW cash flow requirements;
- Help the Commonwealth and the nation reduce greenhouse gas emissions.

In pursuit of these goals, PGW has designed and will implement the DSM plan according to the following principles:

- Field a portfolio of programs that targets cost-effective gas efficiency savings among all PGW's firm heating customers;

- Maximize delivery efficiency to minimize costs and maximize coverage from the available budget;
- Stage program implementation to permit orderly and sustainable expansion;
- Treat customers in greatest economic need and with most cost-effective opportunities first;
- Support economic development in the City, both directly through more intensive employment of local resources to save natural gas, and indirectly through the economic stimulus generated by increasing the amount of money City households and businesses have available to spend for non-gas goods and services; and
- For retrofit and new construction customers, avoid lost opportunities by seeking comprehensive energy savings of both gas and electric consumption.

Accordingly, PGW's plan will provide benefits not only to its customers but also to the Company, the City and the region.

Q. Given all the other sources of conservation and energy efficiency assistance from federal initiatives, why is it appropriate for PGW to undertake its proposed plan?

A. Because there is such a huge potential for cost-effective savings in PGW's service territory, the gas savings and associated benefits from PGW's investment will be in addition to those resulting from federally-funded efforts.

IV. Proposed PGW Gas Conservation Programs

Q. What kinds of efficiency opportunities does PGW's DSM Plan target?

A: PGW plans to implement a comprehensive portfolio of seven programs to capture energy efficiency and conservation opportunities available through three distinct types of market transactions. The first and largest source of gas savings is to increase energy efficiency of existing buildings by retrofitting them with supplemental measures (like attic insulation) and with early replacement of inefficient equipment with high-efficiency models (like boilers and furnaces). The second source of efficiency savings is to upgrade the efficiency of new gas-using appliances and equipment when purchased in the normal course as those appliances and equipment require replacement. The third type of opportunity to improve efficiency is before a building or renovation is designed and constructed. PGW's DSM portfolio is explicitly designed and planned to achieve cost-effective savings through all three types of market transactions among residential and non-residential customers by introducing programs to address each in the three-stage sequence.

Q. Describe the programs targeting residential customers.

A: There are three programs that target residential customers. The Comprehensive Residential Retrofit Program and its sibling program, the Enhanced Low-Income Retrofit Program, are both built upon a successful low-income weatherization program started by PGW in 1990. These programs provide free energy audits to identify cost-effective weatherization and heating system replacement opportunities. The Enhanced Low-Income Retrofit program targets participants in PGW's low-income program, the Customer Responsibility Program (CRP). Any cost-effective weatherization measures and heating system retrofits identified by the energy audit will be installed at no cost to the customer.

The Comprehensive Residential Retrofit Program (non-low income) targets the 40% of residential customers with the highest annual consumption of natural gas. The program then works with participating customers to implement any cost-effective opportunities identified by energy audits which PGW will provide free of charge. The customer is provided with information on financing and assistance in installing the measures. Upon installation, the customer receives an incentive to bring the simple payback of the project down to two years.

The Premium Efficiency Gas Appliances and Heating Equipment Program goes up the supply chain to encourage consumers to choose gas powered equipment that is more energy efficient. The program's administrator will work with equipment manufacturers, distributors, retailers, engineers, and contractors to deliver incentives covering 80% of the incremental costs of premium efficiency equipment. Partners will be trained in ways to market the benefits of high efficiency equipment. Technologies covered by this program include high efficiency clothes washers and natural gas powered space and water heating equipment.

Q. Explain the program designs for nonresidential customers.

A: There are four programs that cover nonresidential customers. The Municipal Facilities Comprehensive Efficiency Retrofit Program performs comprehensive retrofits on city owned and operated buildings. The program administrator will work closely with Philadelphia City facility managers, department heads, and financial officers to identify and implement energy efficiency within municipal buildings. The program's main activities are advocacy, engineering assistance, coordination with other programs, and providing advice on financing.

The Commercial and Industrial Equipment Efficiency Upgrades Program takes a similar approach to the Premium Efficiency Gas Appliances and Heating Equipment Program. The program addresses the unique aspects of the commercial and industrial equipment supply chain to increase awareness and installation of high efficiency technologies. To achieve these goals, incentives for 80% of the incremental cost of certain higher efficiency technologies will be provided by equipment manufacturers, distributors, retailers, engineers, and contractors working with the program's administrator.

The High Efficiency Construction Program combines the efforts of property developers, owners, and real estate agents with architects, engineers, builders, and contractors to make energy efficient buildings a priority from the inception of new construction or large scale renovations. The program provides incentives for 80% of the incremental cost of higher efficiency measures. PGW will explore partnerships to aid in the delivery of design and engineering assistance, financing, and incentives.

The Commercial and Industrial Retrofit program is an offshoot of the High Efficiency Construction Program focused on upgrades or changes to existing systems. This includes approaches such as the early retirement of inefficient industrial equipment or installing improved control systems. To drive adoption of higher efficiency measures, the program will work closely with the participants to deliver a custom incentive based on buying down the payback time for the project.

Q. Are PGW's programs modeled after successful DSM efforts elsewhere?

A: Yes. In helping PGW draft the plan, I carefully examined programs and their results from all over the Northeastern US, as well as efforts in Canada, California, and the Midwestern US.

Q. Can you demonstrate how PGW's programs are modeled on best practices by industry leaders?

A: PGW's proposed program designs incorporate the same proven strategies employed by the nation's most successful natural gas energy efficiency efforts. Programs run by Vermont Gas Systems (VGS), NSTAR (serving the Boston area), and the Southern California Gas Company (SoCalGas) illustrate key features in common with the programs PGW proposes. For example, these three utilities' programs offer both residential and commercial retrofit programs that begin with free energy audits to identify savings and install a variety of low-cost, high-benefit measures. PGW's residential retrofit programs use advanced air-sealing and insulation practices, as well as heating system retrofits. The programs target high-use customers while also allowing self-selected participation. The high-use customers receive assistance and incentives for installing energy efficiency measures identified in the audit, while the low-income participants have cost-effective measures directly installed at no cost to them. And as both an added incentive and an additional source of energy savings, PGW's residential retrofit programs will provide for direct installation of an average of ten high-performance, high-efficiency lamps in each treated household. This improves the program's attractiveness to potential participants, increasing participation, total gas savings, and net economic benefits.

Providing incentives to defray the efficiency cost premium for the purchase of high-efficiency new equipment has been the cornerstone of gas energy efficiency efforts across the country for decades. As new technologies enter the marketplace and codes and standards eliminate the least-efficient equipment, the range of technologies covered changes over time. PGW's minimum efficiency requirements will be updated to meet increasingly strict federal standards and to align with minimum requirements with other leading efforts from utilities such as VGS, NSTAR, National Grid, and SoCalGas. Like PGW's, these programs also aggressively targeted market participants throughout the supply chain.

The most successful new construction programs take an integrated approach to building efficiency, coordinating the multiple functions and stages associated with building construction with the array of efficiency opportunities across building energy sources, and end uses. Financial incentives typically defray most or all of the incremental cost of high-efficiency design, equipment, and construction over and above standard market practice.

This approach is exemplified in the efficient construction programs of the three utilities mentioned before. VGS provides 25% to 50% of the incremental cost for nonresidential new construction projects. NSTAR, VGS, and SoCalGas base incentives for residential buildings on the ENERGY STAR® Home certification, and scale up the incentive for additional efficiency measures.

Q: **How important is integration with other programs in best practices and how does this apply in PGW's current plans?**

A: Integration has proved to be critical to maximizing cost-effective savings from program expenditures. It helps avoid lost opportunities, reduce duplications in effort, cut costs, and achieve greater and deeper savings. For retrofit programs, leading gas utilities have found great success in working together with electric utilities that offer similar programs. Customers enjoy the greater array of options and incentives while utilities can achieve greater savings and reduce costs through sharing administrative and delivery costs. With regard to reducing cost through the supply chain, integrating efforts with those of other regional gas utilities has proven very effective.

PGW will explore all possible opportunities to integrate its efforts with other utilities in Pennsylvania and beyond. PGW will also work with Pennsylvania's Keystone HELP Program and local banks and credit unions to streamline financing options for retrofit. PGW will help make sure clear information is available to customers on any Federal and State incentives for which customers may be eligible.

V. Proposed PGW Conservation Program Annual Budgets, Gas Savings, and Staging

Q. How much gas will PGW's proposed DSM portfolio save?

A: Table 1 provides the annual incremental and cumulative gas savings expected to be achieved by the portfolio. Projected annual savings climb from 79 BBtu in the first year to 384 BBtu in the fifth year.

Table 1: Annual and Cumulative Gas Savings

Program Year	Year	Incremental Annual BBtu Saved (net)	Cummulative Annual BBtu Saved (net)
1	2010	0	0
2	2011	196	196
3	2012	334	530
4	2013	385	915
5	2014	406	1,321

Q: **Are the methods PGW has used to quantify savings from its energy-efficiency programs generally consistent with those adopted by the Commission regarding electric utility DSM programs under Section 129?**

A: Yes, to the best of my knowledge. I base this conclusion on my review of the Public Utility Commission's (PUC) order of June 18, 2009 in Docket No. M-2009-2108601 and its appendix regarding the Total Resource Cost (TRC) Test.

Q. **How much will it cost PGW's ratepayers to acquire these gas savings?**

A: Spending ramps up from $0.25 million in 2010, to over $15 million in 2014. Table 2 shows the year by year total spending.

Table 2: Annual Spending (Nominal $)

Program Year	Year	Annual Spending (Nominal $)
1	2010	$ 350,000.00
2	2011	$ 10,097,331.85
3	2012	$ 13,237,762.66
4	2013	$ 14,876,262.33
5	2014	$ 15,653,289.04
	Total:	**$ 54,214,645.87**

Q: How will PGW stage the programs to achieve these results?

A: In the first program year, PGW will work on designing and implementing, as appropriate, the rollout of the Low Income Retrofit Program, Comprehensive Residential Retrofit Program, and Premium Gas Appliances and Heating Program.

Beginning in 2011, PGW will leverage experience with the CWP and its pilot program to deliver the Enhanced Low-Income Retrofit Program. By targeting consumption of low income customers as the highest priority, PGW's program will provide the quickest benefits to all residential customers because the cost of high usage by CRP customers imposes a significant subsidy on other firm customers. As this program penetrates the market, that subsidy will be reduced. PGW will also use 2011 to continue technical, economic, and financial assessment of municipal efficiency projects, and develop detailed plans for the other programs in the portfolio to be launched in its first stages in 2011.

Further into 2011, as the Enhanced Low Income Retrofit Program reaches its targeted annual pace, the same services will be rolled out to other high-use residential customers. PGW will also roll out the Premium Efficiency Gas Appliances and Heating Equipment Program, and the Commercial and Industrial Equipment Efficiency Upgrade Program.

The High-Efficiency Construction Program will be introduced in 2012. By then, the municipal facilities program and all of the residential programs will be at or near their targeted activity levels. The C&I programs will continue to ramp up and will reach their maximum participation levels in the fifth year of the portfolio.

Q: How did you arrive at 20% savings for the residential retrofit programs?

A: As detailed in our response to the OCA's Informal Data Request Set III Question 7, current savings for participants in the CWP average just over 15%. PGW continues to improve the CWP as results are evaluated and experienced is gained. PGW will use the following techniques to increase per customer savings to 20%:

- Enhance thermostat deliveries and educational techniques, as practiced by the current CWP contractors ECA and Honeywell;
- Utilize the knowledge gained from the pilot program to increase the number of furnace and boiler early retirements;
- Aggressively pursue air sealing, especially in high-use homes;
- Increase the number of roof insulation installations, and improve their quality through infrared camera inspections; and
- Provide more under-porch partitions (an insulated and sealed wall to separate the section of a basement that extends under a porch).

Q: How do PGW's proposed program spending and savings compare with other utilities?

A.: Table 3 compares average spending and savings from PGW's five year portfolio against averages from the actual results and planned programs of other natural gas DSM portfolios.

Table 3: Comparison of PGW and Other Natural Gas DSM Program Averages

Program	Savings % of Sales	Spendng per Annual Therm Saved	Spendng per Lifetime Therm Saved
Residential			
PGW (2010 - 2014)	0.59%	$ 3.47	$0.35
Actual and Planned Program Results	0.43%	$ 5.32	$0.54
Nonresidential			
PGW (2010 - 2014)	0.29%	$ 2.76	$0.28
Actual and Planned Program Results	0.39%	$ 3.45	$0.35
Total			
PGW (2010 - 2014)	0.53%	$ 3.55	$ 0.36
Actual and Planned Program Results	0.53%	$ 3.00	$ 0.29

PGW's planned portfolio aims to achieve greater savings than the average savings achieved by residential programs of other utilities. Savings for PGW's total portfolio, both from residential and nonresidential programs, are right in line with the average. Additionally, the cost of savings for nonresidential programs is marginally below the average of other companies, while that for residential programs is substantially below other utility program averages.

Q. Can you draw any direct comparisons between PGW's individual program costs and savings and those of other leading gas DSM programs?

A: Table 4 shows how PGW's programs compare against leading programs in the Northeast.

Table 4: Comparison of PGW and Leading Northeastern Natural Gas DSM Programs

Program	Savings % of Sales	Spendng per Annual Therm Saved	Spendng per Lifetime Therm Saved
Residential			
PGW (2010 - 2014)	0.59%	$ 3.47	$0.35
Actual and Planned Program Results	0.33%	$ 6.27	$0.64
Nonresidential			
PGW (2010 - 2014)	0.29%	$ 2.76	$0.28
Actual and Planned Program Results	0.50%	$ 5.15	$0.52
Total			
PGW (2010 - 2014)	0.53%	$ 3.55	$0.36
Actual and Planned Program Results	0.58%	$ 3.03	$0.31

This table shows that PGW's portfolio savings as a percentage of sales closely follow the average of leading Northeastern DSM portfolios. PGW achieves more savings from the residential sector due to the faster ramp up of existing DSM efforts. Other leading programs have higher savings from nonresidential sector programs due to the later staging of PGW's efforts. If we only look at the last three years of the program, PGW averages a 0.49% savings as a percentage of nonresidential sales at an average cost of $4.37 per therm, which is more in line with other leading programs. States whose programs are used in Table 4 include Massachusetts, New Hampshire, Vermont, and New York.

Vermont Gas's Energy Extender Portfolio provides results for a similar set of programs to PGW's planned efforts. VGS is often recognized as a national leader in DSM. The two portfolios share a similar make up of programs and are active in the same general geographic region. Table 5 shows recent results for the Energy Extender Program next to PGW's proposed plan.

Table 5: VGS Residential Program Results and PGW Planned Residential Programs

Vermont Gas System's EnergyExtenders			PGW Portfolio Plans		
Year	Savings % of Sales	Spendng per Annual Therm Saved	Year	Savings % of Sales	Spendng per Annual Therm Saved
			Residential		
2006	0.87%	$ 3.09	2012	0.77%	$ 4.01
2007	0.80%	$ 3.32	2013	0.85%	$ 4.02
2008	0.96%	$ 3.22	2014	0.85%	$ 4.12
Average:	**0.88%**	**$ 3.21**		**0.82%**	**$ 4.05**

The years 2012 through 2014 best represent the costs and performance of PGW's portfolio when most of the programs are operating at their full potential, and thus the best comparison with VGS, which has been operating gas DSM programs in Vermont for the past decade. Both programs achieve a high level of savings as a percentage of sales for similar costs per therm. The higher savings and lower cost of the Vermont programs stem from PGW's aim of providing services to low income households. While VGS also prioritizes low-income applicants, PGW will be more aggressive in pursuing and installing measures for this customer class.

NationalGrid's subsidiaries in New York State are also in the late planning stages for a natural gas DSM portfolio. In the commercial and industrial sector, as with PGW's plans, NationalGrid will promote efforts through incentives and technical assistance. Participants follow either a custom or prescriptive track to receive incentives. NationalGrid has made coordination with existing programs, specifically those run by the New York State Energy Research Development Authority (NYSERDA), a priority. Table 6 shows that both utilities have similar expectations for the cost of annual therms saved.

Table 6: Comparison of National Grid New York's Gas C&IDSM Plans to PGW

NationalGrid (NY)		PGW	
Year	Spendng per Annual Therm Saved	Year	Spendng per Annual Therm Saved
2006	$ 4.54	2012	$ 5.26
2007	$ 4.95	2013	$ 4.19
2008	$ 4.94	2014	$ 3.90
Average:	**$ 4.81**		**$ 4.45**

Q: **Can you compare PGW's projections to any third party studies on best practices?**

A: A working paper issued by ACEEE in August 2009 titled "Saving Energy Cost-Effectively" examines the cost of saved energy (CSE) from seven leading state-level natural gas DSM portfolios. CSE measures the levelized cost of lifetime energy savings. I compare these results to those from the PGW projections in Table 7. The states covered by the study include California, Connecticut, Iowa, New Jersey, New York, Oregon, and Wisconsin.

Table 7: Comparison of CSE for PGW ad Leading Gas DSM Portfolios

	CSE Using Paper's Assumptions	CSE Using Internal Assumptions	Achieved CSE from Seven Leading States
PGW			
2010	$ -	$ -	
2011	$ 0.44	$ 0.53	
2012	$ 0.34	$ 0.41	
2013	$ 0.33	$ 0.40	
2014	$ 0.33	$ 0.39	
AVERAGE	**$ 0.29**	**$ 0.34**	**$0.34**
MEDIAN	**$ 0.33**	**$ 0.40**	**$0.32**
MIN	**$ -**	**$ -**	**$0.14**

Table 7 shows two scenarios. The first scenario calculates the CSE using the same assumptions that the paper does. It uses a discount rate of 5% and an average measure life of 18 years. The second scenario shows the CSE using the more conservative assumptions that went into the PGW portfolio analysis. This uses a discount rate of 5.9% and an average measure life of 15 years. In both PGW portfolio scenarios, the CSE declines each year as the programs ramps up. Both of PGW's annual CSE from 2012-2014 fall right in line with the mean and median values from the other state's portfolios. The paper's assumptions yield an average CSE of $0.29 and the internal assumptions lead to $0.34, compared to a mean of $0.34 and median of $0.32 for the other states.

VI. Benefits and Costs of Proposed PGW Conservation Investment Portfolio

Q. How did you assess the benefits and costs of PGW's proposed DSM portfolio?

A. PGW compared the benefits and costs of gas DSM investment from two perspectives: total resource costs, and gas system costs. The primary test for

DSM cost-effectiveness is the TRC test, which accounts for all the benefits and costs to the economy of the efficiency investment, regardless of who enjoys or pays them. This is the test the PUC has adopted for assessing the economic merits of electric utility DSM programs. Benefits are valued at the avoided marginal costs of gas supply, as discussed further in the testimony of PGW witness Chernick. Benefits also include avoided electricity costs for measures that save electricity. Costs consist of the efficiency measure costs and the costs of marketing, technical assistance, management, and other program functions that are more or less fixed with respect to the volume of program activity and/or the number of efficiency measures installed. The net benefits to the economy from cost-effective DSM investment are the difference between the present worth of benefits and costs of the programs over the lifetimes of all the measures installed as a result of the program.

The gas system perspective, by contrast, counts only those benefits and costs of DSM programs that fall within the sphere of costs paid by all gas system ratepayers. It indicates the extent to which a program or portfolio of programs benefits the group of ratepayers supporting the investment. The gas system perspective omits avoided electricity costs from the calculation of benefits; it also omits the portion of efficiency measure costs paid for directly by participants.

Q. What are the lifetime costs and benefits you estimate from implementing PGW's DSM plan?

A: Table 8 is an overview of the cost-effectiveness of PGW's planned portfolio.

Table 8: Cost-Effectiveness Analysis of PGW Portfolio

PROGRAM	Total Resource PV Benefits	Total Resource PV Costs	PGW PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Comprehensive Residential Heating Retrofit	$ 37,679,103	$ 21,617,885	$ 10,950,799	$ 16,061,218	1.74
Enhanced Low-income retrofit	$ 37,044,268	$ 21,972,192	$ 22,316,612	$ 15,072,076	1.69
Premium efficiency gas appliances and heating equipment	$ 26,519,663	$ 4,740,331	$ 4,740,331	$ 21,779,332	5.59
Commercial and industrial equipment efficiency upgrades	$ 1,656,514	$ 1,366,816	$ 1,170,821	$ 289,698	1.21
Municipal facilities comprehensive efficiency retrofit	$ 3,676,093	$ 3,290,862	$ 1,734,161	$ 385,230	1.12
High-efficiency construction	$ 3,268,894	$ 1,925,587	$ 1,925,587	$ 1,343,307	1.70
Commercial and industrial retrofit	$ 3,313,027	$ 2,040,365	$ 995,061	$ 1,272,662	1.62
Portfolio-Wide Costs		$ 854,207	$ 854,207	$ (854,207)	
Total Portfolio	$ 113,157,561	$ 57,808,244	$ 44,687,579	$ 55,349,317	1.96

The portfolio provides PGW customers benefits with a present value of $113.2 million at a cost, including the customer's own investment, of $57.8, for net benefits to customers of $55.3 million. The present value of PGW's costs is $44.7 million. Almost 85% of benefits, $101 million, come from residential programs with a comparable amount of the cost going to the same programs.

Almost all the programs in the portfolio are highly cost effective with benefit-cost ratios above 1.5, except for the municipal and commercial and industrial equipment programs. The Premium Efficiency Gas Appliances and Heating program is particularly cost effective, providing over $26 million in benefits for under $5 million. Almost one third, or $37 million, of the portfolio's savings comes from the Enhanced Low-income Retrofit Program, the cornerstone of PGW's portfolio.

As stated in Section VIII of the narrative description of PGW's plan, which is an exhibit to my testimony, the cost-effectiveness analysis and rate and bill analysis are contained in a functioning, self-documenting MS Excel workbook which is available upon request for easy review.

Q. How will these net benefits stimulate economic activity?

A. The present worth of net benefits under the TRC represents a long-term injection of wealth into the economy. For residential customers, the reduction in the total costs of gas service means an increase in after-tax disposable income. People can use this extra money to save (which today for most means paying down debt) or spend. Likewise, lower gas bills for business customers mean either increased profit margins, more competitive product and service pricing, or both. Businesses will re-invest the resulting extra profits, or distribute them to owners, or some combination of the two. Either way, the total resource cost savings will stimulate additional business activity.[2]

Moreover, the amount of additional economic activity stimulated by the efficiency investment will end up being several times the net benefits due to re-spending within the local, state, and regional economies. While there is doubtless considerable "leakage" as some spending takes place outside Pennsylvania, the majority of the economic benefits stay at the state and local levels.

This economic activity generated by the net economic benefits of efficiency investment is in addition to the economic activity generated directly by expenditures on the part of both PGW and program participants to install the efficiency measures.

Q. How much additional employment do you estimate that PGW's plan will generate?

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[2] In macroeconomic terms, economic activity is defined as aggregate demand. It is the sum of consumer spending, business investment, government spending, and the trade balance of the economy in question, in this case, Pennsylvania's.

A: PGW estimates that between 595 and 991 net new jobs will be created through the proposed DSM efforts. Most of the gains come from shifting spending away from the less job-intensive energy sector towards more job-intensive sectors such as food production. Jobs gained in the energy efficiency sector tend to offset potential job losses in the broader energy services sector. Recent studies from the American Council for an Energy-Efficiency Economy (ACEEE) have estimated that up to 90% of new jobs created from DSM efforts stays within the state where the DSM programs are located. Of the 90%, the majority of those new jobs are created close to where savings occur.

VII. Conclusions and Recommendations

Q: What conclusions do you reach?

A: I conclude that the energy efficiency program portfolio advanced in this proceeding by PGW is cost-effective and therefore economically beneficial to PGW's customers and Pennsylvania's economy. In addition to saving money, energy savings from the portfolio will reduce greenhouse gas emissions, benefitting the environment. These proposals, as described above, are also consistent with other leading gas DSM programs approved by other state Commissions and implemented by utilities in those jurisdictions.

Q: On the basis of these conclusions, what are your recommendations to the Commission?

A: I strongly recommend that the Commission order implementation of this program. Any delay in implementation represents delay of the benefits that will occur.

Q: Does this conclude your testimony?

A: Yes.

RESUME

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Trained as an economist, John Plunkett has worked for 30 years in energy utility planning, concentrating on energy efficiency as a resource and business strategy for energy service providers. He has played key advisory and negotiating roles on all aspects of electric and gas utility demand-side management, including residential, industrial and commercial program design, implementation, oversight, performance incentives, and monitoring and evaluation, and their respective roles in business, regulatory, ratemaking, resource planning and policy decisions. He has led, prepared or contributed to numerous analyses and reports on the economically achievable potential for efficiency and renewable resources.

Plunkett has worked throughout North America and in three Chinese provinces. He has provided expert testimony before regulators in Connecticut, Delaware, the District of Columbia, Florida, Illinois, Indiana, Louisiane, Maine, Maryland, Massachussets, New Jersey, New York, North Carolina, Pennsylvania, and Vermont, as well as in the Canadian provinces of British Columbia, Ontario, and Quebec.

EMPLOYMENT HISTORY

2005-present
Partner and co-founder, **Green Energy Economics Group, Inc.**, Bristol, VT
Three-person consultancy specializing in energy-efficiency and renewable resource portfolios investing in electricity and gas savings. Technical and strategic assistance with development, design, economic and financial analysis, planning, administration, implementation management support, oversight, performance verification and evaluation, design pf performance incentive and pricing mechanisms, and regulatory and ratemaking treatment of utility-funded electricity and gas energy-efficiency portfolios.

1996 – 2005
Partner and co-founder, **Optimal Energy, Inc.**, Bristol, VT.
Strategic planning, implementation management and regulatory support on energy-efficiency investment by regulated and unregulated businesses. Lead consultant for Natural Resources Defense Council on demand-side management portfolio design and economic analysis in two Chinese provinces. Lead author and expert witness on report recommending revamped performance incentive for Connecticut efficiency program administrators, on behalf of Office of Consumer Counsel. Led statewide efficiency and renewable potential study for New York and efficiency potential study for Vermont. Lead author and expert witness on assessment of economically achievable transmission capacity from efficiency resources for Vermont's transmission utility. Advisor on economic analysis of clean energy initiative for the Long Island Power Authority, program cost-effectiveness in Massachusetts and New Jersey collaboratives, and regional market transformation initiatives for Northeast Energy Efficiency Partnerships.

<u>1990 – 1996</u>
Senior Vice President, **Resource Insight, Inc.**, Middlebury, VT.
Provided analysis of DSM resource planning/acquisition and integrated resource planning in numerous states. Investigated regulatory and planning reforms needed to integrate demand-side resources with least-cost planning requirements by public utility commissions. Prepared, delivered and/or supported testimony on wide variety of IRP, DSM, economic, cost recovery and other issues before regulatory agencies throughout North America. Consulted and provided technical assistance regarding utility filings. Responsible for presentations and seminars on DSM planning and evaluation.

<u>1984 – 1990</u>
Senior Economist, **Komanoff Energy Associates**, New York, NY.
Directed consulting services on integrated utility resource planning. Testified on utility resource alternatives, including energy-efficiency investments and independent power. Examined costs and benefits of resource options in over twenty-five proceedings. Supported major investigation into utility DSM investment and integrated resource planning. Designed and co-wrote microcomputer software for evaluating the financial prospects of customer-owned power generation. Wrote and spoke widely on integrated planning issues. Contributed to least-cost planning handbooks prepared by the National Association of Regulatory Utility Commissioners and by the National Association of State Utility Consumer Advocates.

<u>1978 – 1984</u>
Staff Economist, **Institute for Local Self-Reliance**, Washington, D.C.
Project development and management for a non-profit consulting firm specializing in energy and urban economic development. Project manager and economist for an investigation into the economic impact on small generators from electric utilities' grid-interconnection requirements. Coordinated research by three electrical engineers, and analyzed the impact of interconnection costs on wind, hydroelectric and cogeneration projects in seven utility service areas in New York. Provided technical coordination in cases before the District of Columbia Public Service Commission involving gas and electric utility demand management investment, non-utility generation pricing, both for the D.C. Office of People's Counsel.

<u>1977-78</u>
Energy Project Director, **D.C. Public Interest Research Group**, Washington, D.C. 1977. Led energy research and advocacy on campuses of Georgetown and George Washington Universities.

EDUCATION

B.A., Economics, with Distinction, *Phi Beta Kappa*, Swarthmore College, Swarthmore, PA, 1983. Awarded annual departmental Adams Prize in Quantitative Economics.

(Georgetown University School of Foreign Service, Washington, DC, 1975-1977.)

PROJECT EXPERIENCE

ONGOING AND RECENT ASSIGNMENTS -- 2006-PRESENT

DOMESTIC

Vermont

- Senior Policy Advisor to Efficiency Vermont, the world's first Energy Efficiency Utility, operating under contract with the Vermont Public Service Board to deliver statewide energy-efficiency programs for the customers of Vermont's electric utilities. Senior management team member from inception in 2000 through 2007; led program development and planning, 2000-2002. Responsibilities include economic, policy, and evaluation research, analysis and advice. Contract negotiation team member advising on performance goals and incentive mechanism for four successive contracts over twelve years, including major budget increases ordered by the PSB in 2006, and for the $107 million 2009-11 portfolio budget ordered in August 2008. Provided rebuttal testimony in Docket 7466 on switching from the contract model to a long-term order of appointment. Current assignments include technical direction of a 20-year forecast of electricity savings from sustained investment.

- Program design and regulatory support for 5-year investment of $9 million Energy Efficiency Fund, supplementing Efficiency Vermont investment, on behalf of Green Mountain Power. February 2007 – present. Rebuttal testimony on achievable value from additional energy-efficiency investment in utility service area, on behalf of Green Mountain Power in its merger approval application in Docket No. 7213. December 2006-January 2007.

Pennsylvania

- Conservation program design, implementation planning, and regulatory support, for Philadelphia Gas Works. August 2008 – present.

- Analysis and report on costs and benefits of meeting all statewide load growth with energy-efficiency investment, on behalf of Citizens for Pennsylvania's Future (Pennfuture). September 2007.

- Direct and surrebuttal testimony for Citizens for Pennsylvania's Future (Pennfuture) on appropriate levels of efficiency portfolio investment in two rate cases before the Pennsylvania Public Utility Commission: Docket Nos. 00061366 and 00061367 re Metropolitan Edison Company and Pennsylvania Electric Company; and Docket No. R-00061346 re Duquesne Light Company. May - August 2006.

Illinois

- Cost-effectiveness calculator development, oversight of cost/benefit analysis, and regulatory support for 3-year energy-efficiency portfolio for People's Gas. September 2008 – present.

New York

- Advisor on energy-efficiency portfolio design and implementation, for the Economic Development Corporation of the City of New York, in three proceedings before the New York Public Service Commission. One is the PSC's investigation into an energy-efficiency portfolio standard for meeting statewide energy savings goals of 15% by 2015. The second is a collaborative effort with Consolidated Edison's gas division to design a portfolio of gas efficiency programs. The third is evaluation and future redesign of Con Ed Electric's $125 million network-targeted demand-side program. 2007-present.

Connecticut

- Testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel. August –October 2008.

Florida

- Direct testimony on the effect of economically achievable energy efficiency on the need for new coal-fired generation, on behalf of the Sierra Club and other environmental intervenors, Florida Public Service Commission Docket No. 070098-EI. March-April 2007. The PSC denied the requested certificate of public good in June 2007.

INTERNATIONAL

British Columbia, Canada

- Direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada. November 2008 – March 2009.

- Direct testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada. October 2008.

- Direct testimony on energy-efficiency investment spending and savings, British Columbia Hydro and Power Authority, 2006 Integrated Electricity Plan and Long Term Acquisition Plan, Project No. 3698419; and F2007/F2008 Revenue Requirements Application, Project No. 3698416, on behalf of the Sierra Club of Canada (British Columbia Chapter), British Columbia Sustainable Energy Association, and Peace Valley Environment Association. September 2006 – January 2007.

People's Republic of China

Central Government

- Consulting team member on a project developing a national DSM implementation manual for China, sponsored by the National Development and Reform Commission, led by the Natural Resources Defense Council, in cooperation with California's investor-owned utilities, and funded by the international Renewable Energy and Energy Efficiency Programme (REEEP). Wrote chapters concerning performance indicators and cost-effectiveness analysis. 2007-Spring 2008. Manual approved and issued by NDRC May 2009.

Guangdong Provice

- Consultant for the Institute for Sustainable Communities to assist Chinese experts with technical, economic, and financial assessments of industrial retrofit projects in Guangdong Province (in progress). Economic and financial assessment of efficiency retrofits to a ceramics manufacturing plant. 2007-2008. Training and technical assistance on economic and financial assessment of community energy-efficiency and renewable investment projects in three cities. In progress.

- Team leader for Chinese and international consultants on a pre-feasibility analysis for the Asian Development Bank of a 24-year loan to support a $120 million demonstration Efficiency Power Plant (EPP) project in Guangdong province, focusing on industrial, commercial and institutional retrofits. June 2006 – 2007. ADB Board of Directors unanimously approved the loan and its first tranche of projects in June 2008.

Jiangsu Province

- Consulting team leader on development, assessment, and implementation of demand-side management investment portfolios for China, for the Natural Resources Defense Council. (July 2003 – 2007) Responsible for program implementation planning and support (2005-2007). Led modification and application of US-based program and portfolio economic analysis tool for DSM planning. Assisted Jiangsu Province with design and planning for first-stage implementation of Efficiency Power Plant (EPP) programs investing $12 million annually on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling. Directed economic and financial analysis of industrial retrofits for several manufacturers to determine financial incentives offered by the program. October 2005 – 2007. Training and technical support on economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers (2007-2008).

PRIOR ASSIGNMENTS (OPTIMAL ENERGY) -- 1996-2005

- Policy and economic advisor for Massachusetts energy efficiency collaboratives, focusing on regulatory, cost-effectiveness, shareholder incentives and other policy issues and strategies, on behalf of Massachusetts Collaborative Non-Utility Parties. (January 1999 – 2005)

- Co-author (with Optimal Energy and Vermont Energy Investment Corporation), Comments on Efficiency Maine's 2006-2008 Program Plan, on behalf of Maine's Office of Public Advocate. September 2005.

- Team leader providing technical assistance supporting rulemaking to implement energy-efficiency provision of renewable portfolio standard for Pennsylvania, on behalf of Citizens for Pennsylvania's Future (PennFuture). Lead consultant on development of protocols for measuring savings from energy-efficiency investments as tradable credits toward the electricity resource portfolio standard. Protocols adopted by the Pennsylvania Public Utilities Commission. 2005. (February – September 2005)

- Leader of analysis of economically achievable potential for energy-efficiency resources to offset loss of output in the event of early retirement of the Indian Point nuclear generation station, on behalf of the National Academy of Sciences. May-October 2005.

- Co-author (with Paul Chernick) of testimony assessing planned energy-efficiency investments by British Columbia Hydro, on behalf of the British Columbia Sustainable Energy Association and British Columbia Sierra Club, August 2005.

- Written testimony recommending energy-efficiency portfolio investment levels and savings goals in utility merger application before the Pennsylvania Public Utility Commission, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group with and into Exelon Corporation, on behalf of the Pennfuture Parties, June 28, 2005.

- Co-author of and expert witness supporting "Getting Results: Review of Hydro Quebec's Proposed 2005-2010 Energy Efficiency Plan," before the Quebec Energy Board, on behalf of a coalition of business, municipal, and environmental groups (January-March 2005)

- Testimony (with Ashok Gupta) before the New York Public Service Commission supporting joint settlement proposal for 300 MW of additional efficiency investment in Con Edison territory, on behalf of the Natural Resources Defense Council, Pace Energy Project, and the Association for Energy Affordability (December 2004 – January 2005).

- Report and testimony on performance incentives for administrators of conservation and load management programs in Connecticut, on behalf of Connecticut Office of Consumer Counsel. (February 2003 – August 2004). DPUC adopted recommended performance incentive mechanism for 2006 program year.

- Project leader, including report and testimony, for consulting team projecting potential for demand-side resources to defer the need for the Northwest Reliability Project, a major transmission upgrade, on behalf of Vermont Electric Power Company. (November 2001 – December 2004)

- Report and testimony on Opportunities for Accelerated Electrical Energy Efficiency in Québec 2005 – 2012, on behalf of Regroupement National des Conseils Régionaux de L'environnement du Québec, Regroupement des Organismes Environnementaux en Energie and Regroupement pour la Responsabilité Sociale des Entreprises. (March – June 2004)

- Project leader for consulting team assessing technical, achievable and economic potential for energy-efficiency and renewable resources in New York State and five sub regions over 5, 10 and 20 years, on behalf of New York State Research and Development Authority. (January 2002 – August 2003)

- Project leader for consulting team updating statewide projection of economically achievable efficiency potential for state of Vermont, on behalf of the Vermont Department of Public Service. (October 2001 – 2003)

- "A Conservation Contingency Plan for Indian Point: Using California's Success Beating Blackouts to Replace Nuclear Generation Serving Greater New York," prepared for the Natural Resources Defense Council, October 2003.

- "The Achievable Potential for Electric Efficiency Savings in Maine." Projected and compared 10-year C&I costs, savings and benefits (based on technical potential analysis prepared by Exeter Associates). Expert testimony on behalf of the Office of Public Advocate, before the Maine PUC. (October 2002)

- Project leader for consulting team supporting utilities in targeting demand-side resources to optimize distribution investment planning in statewide distributed utility planning collaborative, on behalf of the Vermont Department of Public Service. (September 2001 – December 2002) Led development of DSM scoping tool, an MS Excel spreadsheet for preliminary analysis of the economically achievable potential for energy-efficiency to defer or displace planned distribution investments.

- Advisor on economic analysis for program planning and implementation of multi-year statewide energy-efficiency programs in the New Jersey Clean Energy Collaborative involving all the state's electric and gas utilities and the Natural Resources Defense Council. (April 2000 – June 2003, on behalf of NRDC). Co-directed collaborative work on program development, planning, and implementation for Conectiv. (November 1996 – 2000)

- Analysis and testimony before the Connecticut Siting Council on integrating potential demand reductions from targeted demand-side resources into need assessment for transmission upgrades, on behalf of the Connecticut Office of Consumer Counsel. Docket No. 217. (February 2002 – February 2003)

- Advice and negotiation on policy and scope of utility activities regarding targeted DSM to optimize distribution investment planning, involving Consolidated Edison, PECO Energy, and Orange and Rockland Utilities, on behalf of the Natural Resources Defense Council (Con Ed and PECO) and Pace Energy Project (O&R). (1999 – 2000)

- "Examining the Potential for Energy Efficiency in Michigan: Help for the Economy and the Environment," for American Council for an Energy-Efficient Economy (ACEEE). Analysis and report projecting costs and benefits of aggressive energy-efficiency investment. (January 2003)

- Led consulting team in the preparation of detailed recommendations for implementing strategic plan for acquiring clean power resources for the Jacksonville Electric Authority. (May – September 2001)

- Consultant to Citizens Utilities Corporation, supporting planning and management of investments pursuing maximum achievable levels of optimally cost-effective energy-efficiency in its Vermont Electric Division. (1997 – 2001)

- Consultant to PEPCo Energy Services on building energy-efficiency into retail service offerings. (2000 – 2001)

- Consultant to California Board for Energy-Efficiency, the agency responsible for administering wires-charge funded statewide energy-efficiency programs. Technical service consultant on nonresidential program design. (1997 – 1999)

- Lead consultant on energy product development for consumer energy cooperative, on behalf of Vermont Energy Futures, a non-profit organization spearheading development of a consumer-owned energy cooperative that will bundle electricity with energy-efficiency, renewables, and fossil fuels for residential, low-income, and small non-residential customers. One of key team members who prepared grant application to federal Health and Human Services Department for $800,000 grant supporting development of the co-op. (1997 – 2000)

- Led feasibility analysis and prepared preliminary business plan for bundling electricity, fuel, efficiency services, and green power initially targeting low-income and environmentally-conscious consumers, on behalf of the Energy Coordinating Agency and Conservation Consultants, Inc. (July – December 1997). Consultant on energy and business strategy and planning for Energy Cooperative Association of Pennsylvania, a buyers' cooperative offering electricity, fuel oil, energy-efficiency, and renewable energy to residential and non-profit consumers in eastern and western Pennsylvania. (1998 – July 1999)

- Lead consultant on energy efficiency program design and planning for Maryland Office of People's Counsel and Maryland Energy Administration. Led research, analysis, and program descriptions and budgets for use in restructuring workshops and legislative development on efficiency and renewable programs supported by system benefits charge. (1998)

- Lead consultant for the Vermont Department of Public Service regarding energy-efficiency investment during and after the transition to electricity restructuring. Lead author of *The Power to Save: A Plan to Transform Vermont's Efficiency Markets*, the DPS filing which calls for development of centrally delivered statewide core programs by an efficiency utility. Prepared written testimony, on behalf of the Vermont Department of Public Service in Docket 5980. (1997 – 1999)

- Technical support to the Burlington (VT) Electric Department in developing energy efficiency programs and policies as part of their resource and business planning. (November 1996 – May 1997)

- Consultant to Vermont Senate Natural Resources and Finance Committees on efficiency and renewable policies in restructuring legislation passed by the Senate but not adopted by the House. Provided technical assistance to support drafting and passage of utility restructuring legislation (S.62). (1997)

- Support to the Vermont Department of Public Service in assessing the performance and expenditures of Green Mountain Power's commercial and industrial DSM programs. Also provided support to the DPS in the evaluation of GMP's actions surrounding the Vermont Joint Owners contract with Hydro Quebec including prudence. (1997).

- Direct testimony and cross-examination relating to the future of DSM under the proposed BG&E/PEPCo utility merger. Case No. 8725 In the matter of Application of BGE, PEPCo & Constellation Energy Corporation for Merger. (1996)

- Written report to the Ontario Energy Board assessing the 1997 DSM Plan filed by Union and Centra Gas LTD in light of prior OEB decisions, as well as specific program plans for residential and non-residential customers. The report also addressed potential changes in gas DSM regulation, cost recovery, and incentives. [*Assessment of the Centra/Union Gas Fiscal 1997 DSM Plan*, Plunkett, Hamilton, and Mosenthal, August 30, 1996.] Testimony before the OEB concerning the report's findings and recommendations. Union/Centra Rate Case, EBRO 493/494. Also prepared a report and testified on Union Gas's DSM program design in EBRO 496/94/95. (July 1996 – November 1996)

PRIOR ASSIGNMENTS (RESOURCE INSIGHT) – 1990-1996

- Consultant on energy-efficiency program design, planning, and policy issues for Maryland utilities including Potomac Electric, Baltimore Gas and Electric, Potomac Edison, Delmarva Power and Light, Southern Maryland Electric Cooperative, Washington Gas, on behalf of Maryland Office of People's Counsel. Coordinator and lead negotiator on DSM collaboratives for Washington Gas, Potomac Electric, Baltimore Gas and Electric, Delmarva Power and Light and Potomac Electric. Projects have included resource planning and allocation, program design, policy, cost recovery, mechanism design, and monitoring and evaluation planning. (1989 – 1997)

- Prepared testimony and supported settlement negotiations concerning the DSM Plan of Jersey Central Power and Light on behalf of the Mid Atlantic Energy Project and New Jersey Public Interest Research Group. Analyzed DSM policy and commercial and industrial programs. Docket No. EE9580349 In the matter of Consideration and Determination of Jersey Central Power and Light Company's Demand Side Management Resource Plan filed pursuant to N.J.A.C. 14:12. (1995)

- Support to the Iowa Office of Consumer Advocate with the review and analysis of MidAmerican's, Interstate Power's and Iowa Electric Services' existing energy efficiency plans. Developed proposals for changes to and modifications of the utilities commercial and industrial energy efficiency programs. (1995 – 1996)

- Testimony and technical support for the Iowa Office of Consumer Advocate in settlement negotiations re IES Utilities C/I DSM programs. Docket No. EEP-95-1. (February 1996)

- Technical support to Florida Power Corporation on development of alternative DSM programs for commercial and industrial customers. (1995 – 1997)

- Supported the development of testimony and negotiations regarding DSM program alternatives for Carolina Power & Light, on behalf of the Southern Environmental Law Center. Docket No. 92-209-E. (1995 – 1996)

- Reviewed and commented on Consumer Gas' C/I DSM programs on behalf of the Green Energy Coalition. (1995)

- Support to the Vermont Department of Public Service in negotiation settlement with Green Mountain Power regarding DSM program design and planning, focusing on target retrofits in load centers under T&D capacity constraints, and increased participation and comprehensiveness of lost-opportunity programs. (1995)

- Consulting services and expert testimony on behalf of the Green Energy Coalition concerning Ontario Hydro's DSM plans and acquisition of lost-opportunity resources. Before Ontario Energy Board H.R. 22. re: Ontario Hydro 1995 Rates and Spending. (1994) and re: Ontario Hydro's Bulk Power Rates for 1993. Ontario Energy Board HR-21. (1992)

- Reviewed Tennessee Valley Authority programs and environmental planning for the Tennessee Valley Energy Reform Coalition. (November 1994 – July 1995)

- Prepared and defended direct testimony on gas and electric Demand-Side Management/Integrated Resource Planning guidelines before the North Carolina Public Utilities Commission. Docket No. E-100, SUB 64A in the matter of Request by Duke Power Company for Approval of a Food Service Program, Docket E-100, SUB 71 In the matter of Investigation of the Effect of Electric IRP and DSM Programs on the Competition Between Electric Utilities and Natural Gas Utilities. (1994)

- Prepared and defended expert testimony and led analyses of demand-side management and fuel switching opportunities in Central Vermont Public Service territory, on behalf of the Vermont Department of Public Service. Project involved detailed analysis of measure costs, savings, and cost-effectiveness. Vermont Public Service Board, Docket 5270-CVPS-1&3. (1994)

- Prepared and defended expert testimony for the Vermont Department of Public Service on prudence of demand-side management in CVPS rate case. Vermont Public Service Board, Docket 5724. (May – August 1994)

- Directed and supported the preparation of joint testimony for Enersave, an efficiency service provider. Before the New York Public Service Commission, Case No. 94-E-0334. (September 1994)

- Joint testimony with Jonathan Wallach for the New York Public Utility intervenors reviewing

1994 LILCo DSM Plan. Before the New York Public Service Commission. P.S.C. Case No. 93-5-1123. (May 1994)

- Contributed to the critique of PECO Demand-Side Management Plan for the Nonprofits Energy Savings Investment Program. (February 1994)

- Provided direct testimony in a proceeding to investigate restrictions on DSM that could give one utility (gas or electric) an unfair competitive advantage over another (electric or gas, respectively). Before the Louisiana Public Service Commission Docket No. U-20178 Re: Louisiana Power & Light Company Least Cost Resource Plan. (1994)

- Provided expert testimony in support of PEPCo's DSM implementation. Before the Public Service Commission of the District of Columbia. Case No. 929. (1993)

- Prepared written testimony for the Maryland Office of People's Counsel analyzing potential for demand-side resources to offset need for power for proposed coal-fired plant. Delmarva Power & Light Company Dorchester Power Plant Certificate of Public Convenience and Necessity. Maryland PSC Case No. 8489. (January 1993)

- Coordinated testimony assessing the planning process, screening analyses, and cost-recovery proposals of the Detroit Edison Company for its demand-side management programs. Estimated potential levels of savings; identified improvements to the utility's proposed cost-recovery, lost-revenue, and incentive mechanisms; and recommended regulatory signals consistent with least-cost planning. Provided economic and regulatory advice, consulting services, and oversaw preparation of testimony. Michigan PSC Case No. U-10102. (1992)

- Economic and regulatory advice, consulting services, and supervision of testimony preparation. Provided technical services encompassing demand-side management program monitoring and evaluation, cost recovery, and review of second efficiency plans. Before the Iowa Utilities Board, Iowa Power and Light Docket No. EEP-91-3 and Interstate Power Company Docket No. EEP-91-5. (1992)

- Consulting on policy and resource-allocation issues on behalf of the Vermont Department of Public Service as part of DSM-program-design collaboratives with Vermont Gas. (1990 – 1991), Citizens Utilities (1990 – 1991), Central Vermont Public Service Corporation (1990) and Green Mountain Power. (1990)

- Comprehensive assessment of Ontario Hydro's 25-year resource plan. Directed work by over a dozen consultants. The study encompassed load forecasting; assessing DM potential and costs; resolving DM-implementation, resource-integration, and institutional issues; assessing all resource costs, including externalities; assessing costs of all supply resources, including non-utility generators; and estimating avoided costs. (1990 – 1992)

- Support to the Pennsylvania Energy Office in its evaluation of Pennsylvania electric utility demand-management plans by preparing testimony and co-authoring a comprehensive, five-volume study of all aspects of demand management. This document surveys issues related to integration of demand-management resources into utility planning, and reconciling least-cost planning objectives with rate-impact constraints; discusses strategies for utility intervention to remove market barriers to energy conservation; evaluates cost-recovery mechanisms for demand-management expenditures by utilities; explores issues related to the screening demand-management measures and programs; and examines direct costs, risk, and externalities avoidable through demand management. (1991 – 1993)

- Provided analysis of 1991 - 1992 New York electric utility DSM plans, and support for the analysis of 1993 - 1994 DSM Plans on behalf of Pace University Center for Environmental and Legal Studies, and Vladeck, Waldman, Elias & Engelhard, P.C., Counsel for the Class of LILCo Ratepayers in County of Suffolk *et al.* v. LILCo *et al.* Proceeding to Inquire into the Benefits to Ratepayers and Utilities from Implementation of Conservation Programs that will reduce Electric Use, New York Public Service Commission Case No. 28223. (1990, 1992, 1994)

- Reviewed Demand Side Management regulations and DSM compliance filings of four New Jersey utilities on behalf of the New Jersey Division of Rate Counsel. Demand Side Management Resource Plan of Jersey Central Power & Light Company. Docket No. EE-92020103. (1992)

- Identified energy-efficiency resources missing from FPL's resource plan that could provide economical substitutes for proposed power supply option. Expert testimony also addressed environmental costs avoided by DSM. Florida PSC Docket No. 920520-EG, In Re: Joint Petition of Florida Power and Light and Cypress Energy Partners, Limited Partnership for Determination of Need. (1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor, In the matter of the Petition of Indianapolis Power & Light Company for a Certificate of Public Convenience and Necessity for the Construction by it of Facilities for the Generation of Electricity and Submission and Request for Approval of Plan to meet future needs for Electricity. Cause No. 39236. (August 1991 – May 1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor. In the matter of the Petition of PSI Energy, Inc. Filed Pursuant to the Public Service Commission Act, as Amended, and I.C. 8-1-8.52 for the Issuance of Certificates of Public Convenience and Necessity to Construct Generating Facilities for the Furnishing of Electric Utility Service to the Public and for the Approval of Expenditures for such Facilities. Cause No. 39175. (June 1991 – February 1992)

- Testimony and surrebuttal for the Delaware PSC Staff. Before the Delaware Public Service Commission Staff, In the Matter of the Application of Delmarva Power & Light Company for Approval of 48 MW Power Purchase Agreement with Star Enterprise, PSC Docket No. 90-16. (January 1991)

- Prepared comments on IRP principles and objectives for the Southern Environmental Law Center. Commonwealth of Virginia State Corporation Commission Order Establishing Commission Investigation to Consider Rules and Policy Regarding Conservation and Load Management Programs, Case No. PUE900070. (1991)

PRIOR ASSIGNMENTS (KOMANOFF ENERGY ASSOCIATES) – 1984-1990

- Advisor to the Vermont Public Service Board. Supported formulating issues, conducting hearings, deciding policy, and drafting opinions and orders on DSM planning programs, and ratemaking. Advised the Board's hearing officer on numerous decisions concerning policy and process, including cost-benefit analysis, design and coverage of utility energy-efficiency programs and integrated planning requirements. Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy, Docket No. 5270. (1988 – 1990)

- Technical advisor to the Public Utility Law Project of New York. Recommended economic principles for planning utility DSM investment for low-income customers in New York. Proceeding on Motion of the Commission to Determine Whether the Major Gas and Combination Gas and Electric Utilities Subject to the Commission's Jurisdiction Should Establish and Implement a Low-Income Energy Efficiency Program, Case 89-M-124. (1990).

- Technical assistance and advice on behalf of the South Carolina Department of Consumer Affairs on all aspects of Integrated Resource Planning and DSM planning including cost-effectiveness tests for South Carolina PSC investigation into Electric Utility Least-Cost Planning, Docket No. 87-223-E. (1987 – 1992)

- Prepared and defended expert testimony for the Indiana Office of Utility Consumer Counselor on potential for DSM to defer need for new generating capacity. Petition of Southern Indiana Gas and Electric Co. for Approval of Construction and Cost of Additional Electric Generation and for Issuance of a Certificate of Need Therefore, Indiana Utility Regulatory Commission, Cause No. 38738. (September 1989)

- Prepared and defended expert testimony for the Illinois Citizens Utility Board on adequacy of Commonwealth Edison's DSM efforts. Rulemaking Implementing Section 8-402 of the Public Utilities Act, Least-Cost Planning, Illinois ICC Docket No. 89-0034. (July 1989)

- Supported the Vermont Public Service Board with analysis, findings, and conclusions regarding the need for power based on potential DSM resources. Application of Twenty-Four Electric Utilities for a Certificate of Public Good Authorizing Execution and Performance of a Firm Power and Energy Contract with Hydro-Quebec and a Hydro-Quebec Participation Agreement, Docket No. 5330. (1989 – 1990)

- Cost-benefit analysis for the City of Chicago examining alternatives to the renewal of Commonwealth Edison's franchise. (1989)

- Co-author (with J. Wallach) of *The Power Analyst*, integrated spreadsheet-based software for projecting the economic and financial performance of renewable and cogeneration projects, for the New York State Energy Research and Development Authority. Project manager, economic analysis. (1989)

- Advisor for the South Carolina Department of Consumer Affairs. Assessed costs and benefits of long-term power contract. In the Matter of Duke Power Company, Federal Energy Commission, Docket No. ER89-106-000. (January 1989 – March 1990)

- Analyzed and provided expert testimony on the economic potential for cost-effective DSM to substitute for capacity and energy from a combined cycle generating plant. Application of Potomac Electric Power Company for Certificate of Public Convenience and Necessity for Station H, Maryland PSC Docket No. 8063 Phase II. (1988)

- Examined, compared, and recommended appropriate cost-effectiveness tests for the DSM portion of the Massachusetts Department of Public Utilities investigation into the Pricing and Ratemaking Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities. Docket No. 86-36. (1988)

- Testimony for the District of Columbia Office of People's Counsel on electric and gas utility least-cost planning. Application of the Potomac Electric Power Company for Changes to Electric Rate Schedules, D.C. PSC Formal Case 834 Phase II. (April and June 1987)

- Cross-examination for the Connecticut Division of Consumer Counsel to defend KEA's financial assessment of CL&P's ability to withstand Millstone 3 disallowance. Investigation into Excess Generating Capacity of Connecticut Light & Power Company, Connecticut DPUC Docket No. 85-09-12. (April 1986)

- Cross examination for the Connecticut Division of Consumer Counsel to defend financial and statistical model supporting KEA's findings of CL&P construction imprudence. Retrospective Audit of the Prudence of the Construction of Millstone 3, Connecticut DPUC Docket 83-07-03. (March 1986)

- Cross-examination for the Pennsylvania Office of Consumer Advocate, defended quantification of imprudence findings by O'Brien/Kreitzberg & Associates regarding PECO's construction management of the Limerick 1 project. Pennsylvania PUC v. Philadelphia Electric Company Docket R-850152. (February 1986)

- Prepared and defended direct and surrebuttal testimony for the Pennsylvania Office of Consumer Advocate critiquing utility conservation and cogeneration assumptions and presented alternative 20-year electricity sales projection. Pennsylvania PUC Limerick 2 Investigation Docket I-840381. (April 1985)

PRIOR ASSIGNMENTS (INSTITUTE FOR LOCAL SELF-RELIANCE) – 1978-1983

- Technical and economic analysis of small-generator grid interconnection of seven New York electric utilities for the New York Energy Research and Development Authority. Project manager, economic analysis. (1983)

- Written testimony on behalf of the Alaska Public Interest Research Group implementing PURPA 210. Before the Alaska PUC. (1981)

- Written and oral testimony in oversight hearings on state implementation of the Public Utility Regulatory Policy Act of 1978 (PURPA). U.S House of Representatives Subcommittee on Energy Conservation and Power. (1981)

- Written and oral testimony in rulemaking for the Public Utility Regulatory Policy Act of 1978 (PURPA) on behalf of ILSR, before the Federal Energy Regulatory Commission. (1979)

PUBLICATIONS/PRESENTATIONS

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont, Part Dieux" with Bruce Bentley 2008 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2008.

"Demand-Side Management Strategic Plan for Jiangsu Province, China: Economic, Electric and Environmental Returns from an End-Use Efficiency Investment Portfolio in the Jiangsu Power Sector," with Barbara Finamore and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont's 'Southern Loop,'" with Bruce Bentley and Francis Wyatt, , 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"Comparative Performance of Electrical Energy Efficiency Portfolios in Seven Northeast States," with Glenn Reed and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

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Exhibit___JJP-2: Actual and Planned Expenditures and Savings For Leading Gas Efficiency Program Administrators (Nominal $)

	Residential					Non-Residential					Total						
	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Spending per Lifetime Therm Saved	Spending per Therm Sold
PGW PROJECTIONS																	
Philadelphia Gas Works																	
2010	$ 0.30	-	394	0.00%	$0.00	$ 0.05		114	0.00%	$0.00	$ 0.35	-	508	0.00%	$0.00	$0.00	$ 0.001
2011	$ 9.92	1.96	392	0.50%	$5.06	$ 0.48	0.00	114	0.00%	$0.00	$ 10.40	1.96	506	0.39%	$5.31	$0.54	$ 0.021
2012	$ 12.19	3.01	390	0.77%	$4.05	$ 1.69	0.33	113	0.29%	$5.13	$ 13.88	3.34	503	0.66%	$4.15	$0.42	$ 0.028
2013	$ 13.36	3.30	388	0.85%	$4.05	$ 2.46	0.55	113	0.49%	$4.45	$ 15.81	3.85	501	0.77%	$4.11	$0.42	$ 0.032
2014	$ 13.73	3.30	386	0.85%	$4.16	$ 3.25	0.77	112	0.68%	$4.23	$ 16.97	4.06	498	0.82%	$4.18	$0.43	$ 0.034
ACTUAL																	
NSTAR (Massachussets)																	
2004	$ 3.06	0.29	231	0.13%	$10.38	$ 1.02	0.44	239	0.18%	$2.32	$ 4.08	0.73	470	0.16%	$5.55	$0.57	$ 0.0087
2006	$ 2.98	0.28	193	0.14%	$10.75	$ 0.96	0.61	225	0.27%	$1.58	$ 3.94	0.89	418	0.21%	$4.45	$0.45	$ 0.0094
2007	$ 3.18	0.26	218	0.12%	$12.14	$ 1.04	0.51	249	0.21%	$2.02	$ 4.22	0.78	467	0.17%	$5.43	$0.55	$ 0.0090
Southern California Gas (California)																	
2006	$ 12.98	2.82	2,480	0.11%	$4.61	$ 13.22	8.81	3790	0.23%	$1.50	$ 26.20	11.62	6,270	0.19%	$2.25	$0.23	$ 0.0042
2007	$ 41.15	3.54	2,460	0.14%	$11.63	$ 24.74	23.28	3880	0.60%	$1.06	$ 65.89	26.81	6,340	0.42%	$2.46	$0.25	$ 0.0104
Enbridge (Canada & US)																	
2007		18.65	1,581	1.18%			14.63	2571	0.57%		$ 22.00	33.28	4,152	0.80%	$0.66	$0.07	$ 0.0053
Union Gas (Ontario)																	
2007	$ 4.09	4.70	1,031	0.46%	$0.87	$ 5.80	26.93	3869	0.70%	$0.22	$ 16.13	31.63	4,900	0.65%	$0.51	$0.05	$ 0.0033
Northern Utilities (New Hampshire)																	
2004	$ 0.29	0.01	17	0.07%	$25.65	$ 0.62	0.06	50	0.12%	$ 10.71	$ 0.91	0.07	67	0.10%	$ 13.13	$ 0.66	$ 0.0135
2005	$ 0.23	0.05	16	0.28%	$4.86	$ 0.41	0.03	49	0.06%	$ 14.62	$ 0.64	0.08	65	0.11%	$ 8.52	$ 0.43	$ 0.0098
2006	$ 0.20	0.05	14	0.34%	$4.22	$ 0.41	0.11	47	0.23%	$ 3.74	$ 0.61	0.16	61	0.26%	$ 3.89	$ 0.19	$ 0.0100
2007	$ 0.28	0.03	16	0.20%	$8.60	$ 0.43	0.10	55	0.17%	$ 4.55	$ 0.71	0.13	72	0.18%	$ 5.57	$ 0.28	$ 0.0099
EnergyNorth Natural Gas, Inc. (NH)																	
2004	$ 0.58	0.23	54	0.42%	$2.56	$ 0.35	0.18	69	0.27%	$10.71	$ 0.93	0.41	123	0.33%	$ 2.26	$ 0.66	$ 0.0076
2005	$ 0.98	0.30	61	0.49%	$3.23	$ 0.60	0.25	77	0.33%	$14.62	$ 1.58	0.56	139	0.40%	$ 2.84	$ 0.43	$ 0.0114
2006	$ 0.84	0.24	53	0.46%	$3.46	$ 0.90	0.34	72	0.47%	$3.74	$ 1.74	0.58	125	0.47%	$ 3.00	$ 0.19	$ 0.0140
2007	$ 1.01	0.23	48	0.48%	$4.45	$ 0.82	0.42	77	0.55%	$4.55	$ 1.83	0.65	125	0.52%	$ 2.83	$ 0.28	$ 0.0147
Vermont Gas Systems, Inc. (Vermont)																	
2003											$ 1.14	0.81	84	0.97%	$ 1.40	$0.14	$ 0.0136
2004											$ 1.12	0.57	86	0.66%	$ 1.97	$0.20	$ 0.0130
2005											$ 1.23	0.74	83	0.89%	$ 1.66	$0.17	$ 0.0148
2006	$ 0.77	0.25	29	0.87%	$3.09	$ 0.51	0.34	51	0.66%	$1.51	$ 1.28	0.59	80	0.73%	$ 2.18	$0.22	$ 0.0160
2007	$ 0.85	0.26	32	0.80%	$3.32	$ 0.66	0.53	56	0.94%	$1.25	$ 1.51	0.79	88	0.89%	$ 1.92	$0.20	$ 0.0171
2008	$ 1.00	0.31	32	0.96%	$3.22	$ 0.70	0.67	57	1.17%	$1.04	$ 1.70	0.98	90	1.10%	$ 1.73	$0.18	$ 0.0189
Iowa (All Investor Owned Utilities)																	
2001	$ 16.56	4.89	670	0.73%	$3.38	$ 1.45	0.89	404	0.22%	$1.63	$ 18.01	5.78	1,074	0.54%	$ 3.12	$0.32	$ 0.0168
2002	$ 14.98	4.14	679	0.61%	$3.62	$ 2.16	0.95	412	0.23%	$2.28	$ 17.14	5.09	1,091	0.47%	$ 3.37	$0.34	$ 0.0157
2003	$ 20.06	4.73	707	0.67%	$4.24	$ 2.18	1.47	420	0.35%	$1.48	$ 22.24	6.20	1,126	0.55%	$ 3.59	$0.37	$ 0.0197
2004	$ 20.47	5.30	654	0.81%	$3.86	$ 2.22	1.31	397	0.33%	$1.70	$ 22.69	6.61	1,051	0.63%	$ 3.43	$0.35	$ 0.0216
2005	$ 25.12	6.61	636	1.04%	$3.80	$ 3.18	2.11	405	0.52%	$1.51	$ 28.30	8.72	1,041	0.84%	$ 3.24	$0.33	$ 0.0272
2006	$ 27.42	6.92	587	1.18%	$3.96	$ 3.65	1.76	382	0.46%	$2.08	$ 31.07	8.68	969	0.90%	$ 3.58	$0.36	$ 0.0321
2007	$ 24.10	5.92	651	0.91%	$4.07	$ 4.34	2.14	521	0.41%	$2.03	$ 28.43	8.06	1,172	0.69%	$ 3.53	$0.36	$ 0.0243
Minnesota Energy Resources Corporation - PNG (Minnesota)																	
2006	$ 1.47	0.54			$2.70	$ 0.28	0.97			$0.29	$ 1.75	1.52			$1.16	$0.12	
2007	$ 1.11	0.42			$2.62	$ 0.45	0.77			$0.59	$ 1.56	1.19			$1.31	$0.13	
Xcel Energy (Minnesota)																	
2007	$ 3.25	1.48			$2.20	$ 2.51	7.41			$0.34	$ 5.76	8.88			$0.65	$0.07	
Great Plains Natural Gas Co. (Minnesota)																	
2006	$ 0.21	0.07			$3.02	$ 0.03	0.07			$0.45	$ 0.24	0.14			$1.74	$0.18	
2007	$ 0.20	0.05			$3.75	$ 0.04	0.12			$0.36	$ 0.24	0.18			$1.38	$0.14	
2008	$ 0.26	0.09			$2.77	$ 0.00	0.00			$0.54	$ 0.26	0.09			$2.71	$0.28	
CenterPoint Energy (Minnesota)																	
2006	$ 3.43	1.60			$2.15	$ 3.65	7.59			$0.48	$ 7.08	9.19			$0.77	$0.08	
2007	$ 3.81	1.65			$2.31	$ 3.42	6.60			$0.52	$ 7.23	8.25			$0.88	$0.09	
2008	$ 4.24	1.74			$2.44	$ 3.63	6.54			$0.56	$ 7.87	8.27			$0.95	$0.10	
Interstate Power and Lighting (Minnesota)																	
2005	$ 0.22	0.10			$2.26	$ 0.23	0.16			$1.44	$ 0.45	0.26			$ 1.74	$0.18	
2006	$ 0.19	0.08			$2.38	$ 0.29	0.16			$1.83	$ 0.48	0.24			$ 2.01	$0.20	
2007	$ 0.18	0.08			$2.25	$ 0.10	0.07			$1.45	$ 0.28	0.15			$ 1.87	$0.19	
2008	$ 0.19	0.07			$2.61	$ 0.17	0.11			$1.51	$ 0.36	0.18			$ 1.95	$0.20	
AVERAGE OF ACTUAL EXPENDITURES AND SAVINGS																	
	$ 6.94	2.11	$ 503.33	0.55%	$ 4.64	$ 2.26	2.88	$ 633.07	0.39%	$ 2.78	$ 9.09	4.65	$ 1,040.76	0.53%	$ 2.93	$ 0.273	$ 0.02

	Residential					Non-Residential					Total						
	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Spending per Lifetime Therm Saved	Spending per Therm Sold
PLANNED																	
Terasen (Canada)																	
2008	$ 7.46	0.93	771	0.12%	$7.99	$ 8.33	1.69	1074	0.16%	$4.92	$ 15.79	2.63	1,844	0.14%	$6.01	$0.61	$ 0.0086
2009	$ 7.59	1.18	771	0.15%	$6.42	$ 10.04	2.49	1074	0.23%	$4.03	$ 17.63	3.67	1,844	0.20%	$4.80	$0.49	$ 0.0096
2010	$ 6.65	0.95	771	0.12%	$6.98	$ 12.84	3.47	1074	0.32%	$3.70	$ 19.49	4.42	1,844	0.24%	$4.41	$0.45	$ 0.0106
Southern California Gas (California)																	
2008											$ 62.00	23.30	6,340	0.37%	$2.66	$0.27	$ 0.0098
2009											$ 73.20	27.20	6,340	0.43%	$2.69	$0.27	$ 0.0115
2010											$ 76.80	28.30	6,340	0.45%	$2.71	$0.28	$ 0.0121
2011											$ 82.20	29.90	6,340	0.47%	$2.75	$0.28	$ 0.0130
2012											$ 89.60	32.30	6,340	0.51%	$2.77	$0.28	$ 0.0141
2013											$ 100.30	35.80	6,340	0.56%	$2.80	$0.29	$ 0.0158
Mid-American (Iowa)																	
2009	$ 15.43					$ 3.55					$ 18.98	3.96	622	0.64%	$4.79	$0.49	$ 0.0305
2010	$ 16.95					$ 5.25					$ 22.20	4.74	624	0.76%	$4.68	$0.48	$ 0.0356
2011	$ 17.95					$ 5.48					$ 23.43	4.97	626	0.79%	$4.71	$0.48	$ 0.0374
2012	$ 19.14					$ 6.37					$ 25.51	5.25	629	0.84%	$4.86	$0.49	$ 0.0406
2013	$ 19.92					$ 6.48					$ 26.41	5.35	631	0.85%	$4.93	$0.50	$ 0.0418
Keyspan Long Island (New York)																	
2009	$ 1.78	0.22	407	0.05%	$8.01												
2010	$ 2.29	0.30	407	0.07%	$7.71												
2011	$ 3.46	0.37	407	0.09%	$9.47												
Keyspan New York (New York)																	
2009	$ 1.99	0.19	1,003	0.02%	$10.30												
2010	$ 3.40	0.35	1,003	0.04%	$9.64												
2011	$ 5.76	0.66	1,003	0.07%	$8.79												
Central Hudson Gas & Electric (New York)																	
2009						$ 0.05	0.01			$7.61							
2010						$ 0.17	0.03			$6.43							
2011						$ 0.17	0.03			$6.43							
Consolidated Edison of New York (New York)																	
2009						$ 0.37	0.04			$9.13							
2010						$ 4.17	0.80			$5.22							
2011						$ 6.05	1.14			$5.30							
NYSERDA FlexTech (New York)																	
2010											$ 1.33	2.37			$0.56	$0.06	
2011											$ 1.70	2.85			$0.59	$0.06	
2012											$ 0.81	1.18			$0.68	$0.07	
2013											$ 0.40	1.18			$0.34	$0.03	
National Grid NY and National Grid Commercial (New York)																	
2009	$ 0.76	1.78			$0.43	$ 3.76	0.83			$4.54	$ 4.52	2.61			$1.73	$0.18	
2010	$ 2.69	0.65			$4.12	$ 12.10	2.45			$4.95	$ 14.79	3.10			$4.77	$0.49	
2011	$ 2.69	0.65			$4.12	$ 12.08	2.45			$4.94	$ 14.77	3.10			$4.77	$0.49	
AVERAGE OF PROJECTED EXPENDITURES AND SAVINGS																	
	$ 8.16	0.57	$ 705.11	0.06%	$ 6.95	$ 4.72	0.86	$ 1,073.53	0.24%	$ 6.06	$ 35.50	12.08	$ 3,742.86	0.61%	$ 2.99	$ 0.305	$ 0.02
AVERAGE OF ACTUAL AND PROJECTED EXPENDITURES AND SAVINGS																	
	$ 7.00	1.75	$ 577.04	0.43%	$ 5.32	$ 3.39	2.70	$ 768.25	0.39%	$ 3.45	$ 16.85	6.88	$ 1,850.55	0.53%	$ 3.00	$ 0.287	$ 0.02

Exhibit____JJP-3: PHILADELPHIA GAS WORKS
Five Year Gas Demand-Side Management Plan
PROGRAM SUMMARIES

PROGRAM	Target Market	Efficiency Technologies Targeted			Market Actors Targeted	Financial Strategies	Delivery Mechanism	PGW Role
		Gas	Electric	Water				
Comprehensive Residential Heating Retrofit	High-use heating customers (customers ranked in the highest 40% in terms of annual consumption	Instrumented air-sealing; attic/wall insulation; high-efficiency windows; high-efficiency furnace early replacement	High-efficiency lighting;	High-efficiency showerheads and aerators; high-efficiency clothes washers	HPwES-certified contractors; material and equipment suppliers	Financial incentives to buy down projects to a 2-year payback period	Private contractors	Lead program administrator for residential retrofit in Philadelphia; explore coordination with other programs
Enhanced Low-Income retrofit	CRP and senior citizen customers				ECA, Honeywell, other providers to be selected through competitive solicitation	Free installation	Implementation contractor(s)	
Premium efficiency gas appliances and heating equipment	Buyers, sellers, and installers of gas space and water heating equipment to residential and small business customers	High-efficiency clothes washers, space- and water-heating equipment	Not applicable		Equipment manufacturers, distributors, retailers/vendors, engineers, contractors, customer buyers	Financial incentives covering 80% of the incremental cost of premium-efficiency equipment	Supply chain	Program administrator; explore coordination with other programs
Commercial and Industrial equipment efficiency upgrades	Buyers and sellers of commercial/industrial gas heating and nonheating equipment	High-efficiency heating and process equipment						
Municipal facilities comprehensive efficiency retrofit	City-owned and -operated public buildings and facilities	High-efficiency boilers and furnaces for space and water heating; high-efficiency building controls; high-efficiency shell improvements	High-efficiency lighting, HVAC, refrigeration	Low-water toilets; high-efficiency clothes washers	Facility managers, department heads, financial officers	Advice on project financing for cost-effective gas-saving measures	Private energy-service contractors selected through competitive bids	Assistance with engineering and economic assessment of retrofit efficiency options, explore coordination with participation in other programs
High-efficiency construction	New construction, remodelling, and renovation efficiency improvements for residential and commerical buildings				Property developers, managers, owners, real estate agents, architects, engineers, builders, contractors	Financial incentives covering 80% of the incremental cost of premium-efficiency equipment and efficiency technologies	Supply chain	Either sole program administrator or explore partnership in coordination with other program(s)
Commercial and Industrial retrofit	Supplemental measures (e.g., boiler controls), early retirement of inefficient equipment; investments planned in coordination with other program(s)					Customized incentives calculated based on payback buydown, including electric and other resource savings.	TBD	

Exhibit___JJP-4: PHILADELPHIA GAS WORKS
DSM PROGRAM PLAN
ANNUAL PROGRAM BUDGETS AND SAVINGS

Program	2010	2011	2012	2013	2014
Annual Budgets (2009$)					
Comprehensive Residential Heating Retrofit	$ 100,000	$ 2,079,620	$ 3,031,268	$ 3,974,140	$ 3,956,590
Enhanced Low-income retrofit	$ 50,000	$ 6,783,440	$ 6,708,440	$ 6,783,440	$ 6,708,440
Premium Efficiency Gas Appliances and Heating Equipment	$ 100,000	$ 659,271	$ 1,702,814	$ 1,627,814	$ 1,702,814
Commercial and Industrial Equipment Efficiency Upgrades	$ -	$ 125,000	$ 274,740	$ 505,666	$ 524,221
Municipal Facilities Comprehensive Efficiency Retrofit	$ -	$ 50,000	$ 667,139	$ 667,139	$ 667,139
High-efficiency Construction	$ -	$ 125,000	$ 342,000	$ 667,501	$ 1,210,002
Commercial and Industrial Retrofit	$ -	$ 75,000	$ 236,361	$ 375,562	$ 459,083
Portfolio Wide Costs	$ 100,000	$ 200,000	$ 200,000	$ 200,000	$ 275,000
Total Porfolio	**$ 350,000**	**$ 10,097,332**	**$ 13,237,763**	**$ 14,876,262**	**$ 15,653,289**
Annual Incremental Energy Saved (BBtu)					
Comprehensive Residential Heating Retrofit	0	57	85	114	114
Enhanced Low-income retrofit	0	101	101	101	101
Premium Efficiency Gas Appliances and Heating Equipment	0	38	115	115	115
Commercial and Industrial Equipment Efficiency Upgrades	0	0	4	9	12
Municipal Facilities Comprehensive Efficiency Retrofit	0	0	16	16	16
High-efficiency Construction	0	0	5	13	26
Commercial and Industrial Retrofit	0	0	8	18	24
Total Porfolio	**0**	**196**	**334**	**385**	**406**

Exhibit____JJP-5: PHILADELPHIA GAS WORKS
Five Year Gas Demand-Side Management Plan
Program Cost-Effectiveness Summary

PROGRAM	Total Resource PV Benefits	Total Resource PV Costs	PGW PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Comprehensive Residential Heating Retrofit	$ 37,679,103	$ 21,617,885	$ 10,950,799	$ 16,061,218	1.74
Enhanced Low-income retrofit	$ 37,044,268	$ 21,972,192	$ 22,316,612	$ 15,072,076	1.69
Premium Efficiency Gas Appliances and Heating Equipment	$ 26,519,663	$ 4,740,331	$ 4,740,331	$ 21,779,332	5.59
Commercial and Industrial Equipment Efficiency Upgrades	$ 1,656,514	$ 1,366,816	$ 1,170,821	$ 289,698	1.21
Municipal Facilities Comprehensive Efficiency Retrofit	$ 3,676,093	$ 3,290,862	$ 1,734,161	$ 385,230	1.12
High-efficiency Construction	$ 3,268,894	$ 1,925,587	$ 1,925,587	$ 1,343,307	1.70
Commercial and Industrial Retrofit	$ 3,313,027	$ 2,040,365	$ 995,061	$ 1,272,662	1.62
Portfolio Wide Costs		$ 854,207	$ 854,207	$ (854,207)	
TOTAL PORTFOLIO	**$ 113,157,561**	**$ 57,808,244**	**$ 44,687,579**	**$ 55,349,317**	**1.96**

Exhibit JJP-6

Philadelphia Gas Works Five-Year Gas Demand-Side Management Plan

December 18, 2009

Submitted For
Review and Approval By the
Pennsylvania Public Utility Commission

Contents

Philadelphia Gas Works
Five-Year Gas Demand-Side Management Plan

I. SUMMARY

Over the next five years, Philadelphia Gas Works (PGW) plans to implement a portfolio of seven demand-side management (DSM) programs designed to reduce customers' energy consumption through end-use efficiency investments. These programs provide technical and financial services to residential and nonresidential customers to help them upgrade the efficiency with which they use energy in their homes and businesses. PGW plans to invest a total of $58 million[1] ($45 million present worth in 2009 dollars) through 2014 to implement these programs, and expects to save 1,321 Billion British Thermal Units (BBTU) annually by the end of 2014.[2] The portfolio's energy savings also reduce greenhouse gas emissions by 1 million tons of carbon dioxide over the lifetimes of all the measure installed over the five-year DSM plan.

Consumption reductions resulting from the DSM portfolio will lower the amount of natural gas PGW has to procure and deliver to serve its customers. Avoided gas supply costs represent the long-term benefits of PGW's DSM plan over the lifetimes of the efficiency measures installed. Today's present worth of these avoided gas supply costs amounts to $99 million, netting $54 million in present worth of cost reductions to the PGW gas system, or a benefit/cost ratio of 2.2.

By the end of the fifth year of portfolio investment, average non-CRP residential customer bills will decrease by 1.2 percent, compared to what they would have been absent PGW's DSM investment. Average rates for this customer class are projected to be 1.0% higher in 2014.[3] Commercial customers will experience an average rate increase of 0.1% at the end of the five-year portfolio investment, along with average bill reductions of 1.1%. Average rates for industrial customers are projected to decrease by 0.4% at the end of the five-year investment period, resulting in an average bill reduction of 0.8%. After the fifth and final year of program expenditures, the portfolio will continue to produce large bill reductions over the remaining lifetimes of the efficiency measures installed due to the DSM portfolio.

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1 This is the sum of nominal dollars assuming 2.0% general inflation (mixed-current dollars, undiscounted). Real portfolio spending totals $54 million in 2009 dollars.

2 PGW seeks recovery of the costs of the program, including revenue lost as a direct result of the program.

3 Portfolio spending, activity levels, and savings are all stated in calendar years, as distinct from PGW's fiscal years, which are accounted for in the analysis of rate and bill impacts from the portfolio.

These net cost reductions to all PGW's customers from lower gas and electric requirements will increase household disposable income and strengthen business profitability throughout Philadelphia, stimulating the creation of between 600 and 1,000 jobs.

PGW's gas DSM plan concentrates on residential retrofits in two phases. First, PGW will enhance the existing low-income program by deepening efficiency investment in treated homes and extending program services to more customers in need. After launching the enhanced low-income program in 2011, PGW plans on expanding the program to the City's non-low income residents. Both retrofit programs upgrade the thermal integrity of the building with added insulation and instrumented air sealing, and in some instances also retire old, inefficient gas furnaces and boilers and water heaters and replace them with new, high-efficiency equipment.

The enhanced low-income program will provide efficiency retrofit services free of charge to the individual customer, just as it does currently. For the rest of PGW's residential customers, the comprehensive retrofit program will offer financial incentives calculated to reduce the investment required by the customer to two year's worth of estimated bill savings. In conjunction with the financial incentive, PGW will assist non-CRP residential customers with accessing third-party financing over a minimum of three years for their investment contributions. The objective of this two-part financial strategy is to provide participating customers with immediate positive cash flow. By the end of the initial five year period, PGW plans to have treated 38,153 customers (15,338 low-income and 22,815 non-CRP residential) through both residential retrofit programs, reaching a combined annual pace of 10,834 per year by 2014. PGW plans to continue the program beyond five years with appropriate regulatory approval.

PGW proposes that both residential retrofit programs will also offer free direct installation of a diverse array of high-efficiency lighting products in customers' homes. These additional measures will produce significant cost-effective electricity savings at costs well below what would have been spent to realize them with a stand-alone electric program. PGW will seek planning and cooperation with other programs, but is prepared to proceed independently because of the significant opportunity the residential retrofit program presents to provide incremental energy savings to customers at very low cost.

Another high priority for 2011 is PGW's plan to work with the City to invest in comprehensive efficiency retrofits in City-owned facilities. In doing so, PGW will help the City undertake the technical and economic assessments required for accessing financial incentives and other services offered by Philadelphia Electric ("PECO").

In the second half of 2011, PGW plans to launch a program to increase the efficiency of gas appliances and heating equipment purchased by residential customers; the plan calls for a companion program for business equipment also beginning in 2012. Also to be initiated in 2012 are a business retrofit program and a new instruction/remodel/renovation program investing in gas and electric efficiency improvements. Due in part to the predominance of electric efficiency savings opportunities compared to gas in commercial buildings, PGW will investigate opportunities to coordinate implementation of these programs with others, but will assume full program administration responsibilities, if partnering proves infeasible.

Table 1 summarizes the present value of costs and benefits of the program portfolio.

Table 1

PROGRAM	Total Resource PV Benefits	Total Resource PV Costs	PGW PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Comprehensive Residential Heating Retrofit	$ 37,679,103	$ 21,617,885	$ 10,950,799	$ 16,061,218	1.74
Enhanced Low-income retrofit	$ 37,044,268	$ 21,972,192	$ 22,316,612	$ 15,072,076	1.69
Premium efficiency gas appliances and heating equipment	$ 26,519,663	$ 4,740,331	$ 4,740,331	$ 21,779,332	5.59
Commercial and Industrial equipment efficiency upgrades	$ 1,656,514	$ 1,366,816	$ 1,170,821	$ 289,698	1.21
Municipal facilities comprehensive efficiency retrofit	$ 3,676,093	$ 3,290,862	$ 1,734,161	$ 385,230	1.12
High-efficiency construction	$ 3,268,894	$ 1,925,587	$ 1,925,587	$ 1,343,307	1.70
Commercial and Industrial retrofit	$ 3,313,027	$ 2,040,365	$ 995,061	$ 1,272,662	1.62
Portfolio-Wide Costs		$ 854,207	$ 854,207	$ (854,207)	
Total Portfolio	$ 113,157,561	$ 57,808,244	$ 44,687,579	$ 55,349,317	1.96

Table 2 summarizes each program's target market and efficiency technologies, market strategies, and delivery mechanism

Table 2

PROGRAM	Target Market	Efficiency Technologies Targeted: Gas	Electric	Water	Market Actors Targeted	Financial Strategies	Delivery Mechanism	PGW Role
Comprehensive Residential Heating Retrofit	High-use heating customers (customers ranked in the highest 40% in terms of annual	Instrumented air-sealing; attic/wall insulation; high-efficiency windows; high-efficiency furnace early replacement	High-efficiency lighting;	High-efficiency showerheads and aerators; high-efficiency clothes washers	HPwES-certified contractors; material and equipment suppliers	Financial incentives to buy down projects to a 2-year payback period	Private contractors	Lead program administrator for residential retrofit in Philadelphia; explore coordination with other programs
Enhanced Low-Income Retrofit	CRP and senior citizen customers				ECA, Honeywell, other providers to be selected through competitive solicitation	Free installation	Implementation contractor(s)	
Premium Efficiency Gas Appliances and Heating Equipment	Buyers, sellers, and installers of gas space and water heating equipment to residential and small business customers	High-efficiency clothes washers, space- and water-heating equipment	Not applicable		Equipment manufacturers, distributors, retailers/vendors, engineers, contractors, customer buyers	Financial incentives covering 80% of the incremental cost of premium-efficiency equipment	Supply chain	Program administrator; explore coordination with other programs
Commercial and industrial equipment efficiency upgrades	Buyers and sellers of commercial/industrial gas heating and nonheating equipment	High-efficiency heating and process equipment						
Municipal Facilities Comprehensive Efficiency Retrofit	City-owned and -operated public buildings and facilities	High-efficiency boilers and furnaces for space and water heating; high-efficiency building controls; high-efficiency shell improvements	High-efficiency lighting, HVAC, refrigeration	Low-water toilets; high-efficiency clothes washers	Facility managers, department heads, financial officers	Advice on project financing for cost-effective gas-saving measures	Private energy-service contractors selected through competitive bids	Assistance with engineering and economic assessment of retrofit efficiency options, explore coordination with participation in other programs
High-efficiency Construction	New construction, remodelling, and renovation efficiency improvements for residential and commerical buildings				Property developers, managers, owners, real estate agents, architects, engineers, builders, contractors	Financial incentives covering 80% of the incremental cost of premium-efficiency equipment and efficiency technologies	Supply chain	Either sole program administrator or explore partnership in coordination with other program(s)
Commercial and Industrial Retrofit	Supplemental measures (e.g., boiler controls), early retirement of inefficient equipment; investments planned in coordination with other program(s)					Customized incentives calculated based on payback buydown, including electric and other resource savings.	TBD	

II. OBJECTIVES OF PGW'S GAS DSM PLAN

PGW's DSM plan has five broad goals.

- Reduce customer bills
- Maximize customer value
- Contribute to the fulfillment of the City's sustainability plan.
- Reduce PGW cash flow requirements
- Help the Commonwealth and the nation reduce greenhouse gas emissions

In pursuit of these goals, PGW has designed and will implement the planned DSM portfolio according to the following principles:

- Field a portfolio of programs that targets cost-effective gas efficiency savings among all PGW's firm heating customers
- Maximize delivery efficiency to minimize costs and maximize coverage from the available budget
- Stage program implementation to permit orderly and sustainable expansion
- Treat customers in greatest economic need and with most cost-effective opportunities first
- Support economic development in the City, both directly through more intensive employment of local resources to save natural gas, and indirectly through the economic stimulus generated by increasing the amount of money City households and businesses have available to spend for non-gas goods and services
- For retrofit and new construction customers, avoid lost opportunities by seeking comprehensive energy savings of both gas and electric consumption

III.PGW's PROPOSED GAS DSM BUDGETS

PGW's five-year DSM portfolio budget totals $58.3 million (nominal dollars). The next section presents annual program-by-program spending (in constant 2009 dollars). The subsequent section compares PGW's DSM spending and savings with those of other gas utilities.

A. Five-Year DSM Program Budgets

PGW plans to increase annual DSM spending from approximately $2.2 million in 2009 to approximately $10.1 million in calendar year 2011, depending on the date of Commission approval. Annual spending will continue to rise each year, consistent with PGW's plan to phase in and ramp up programs over time. As shown in Table 3, annual spending reaches $15.7 million by 2014.

Table 3

Program Budgets (Constant 2009 Dollars)

	2010	2011	2012	2013	2014
Portfolio					
Customer Incentives	$ -	$ 7,894,006	$ 9,976,546	$ 11,274,294	$ 11,966,140
Administration and Management	$ 200,000	$ 700,000	$ 750,000	$ 750,000	$ 750,000
Marketing and Business Development	$ 150,000	$ 350,000	$ 375,000	$ 375,000	$ 375,000
Contractor Costs	$ -	$ 1,013,547	$ 1,255,741	$ 1,497,935	$ 1,497,935
Inspection and Verification	$ -	$ 64,780	$ 114,876	$ 138,434	$ 148,614
On-site Technical Assessment	$ -	$ -	$ 615,600	$ 615,600	$ 615,600
Evaluation	$ -	$ 75,000	$ 150,000	$ 225,000	$ 300,000
Total	$ 350,000	$ 10,097,332	$ 13,237,763	$ 14,876,262	$ 15,653,289
Utility Costs minus Customer Incentives	$ 350,000	$ 2,203,326	$ 3,261,216	$ 3,601,969	$ 3,687,149
	100%	22%	25%	24%	24%
Comprehensive Residential Heating Retrofit	2010	2011	2012	2013	2014
Customer Incentives	$ -	$ 1,401,356	$ 2,102,035	$ 2,802,713	$ 2,802,713
Administration and Management	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Marketing and Business Development	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Contractor Costs	$ -	$ 484,388	$ 726,582	$ 968,777	$ 968,777
Inspection and Verification	$ -	$ 43,876	$ 52,651	$ 52,651	$ 35,101
Evaluation	$ -	$ -	$ 75,000	$ -	$ 75,000
Total	$ 100,000	$ 2,079,620	$ 3,106,268	$ 3,974,140	$ 4,031,590
Enhanced Low-income Retrofit					
Item	2010	2011	2012	2013	2014
Interest Rate Buydown (do not alter this row)	$ -	$ -	$ -	$ -	$ -
Customer Incentives	$ -	$ 6,019,696	$ 6,019,696	$ 6,019,696	$ 6,019,696
Administration and Management	$ 50,000	$ 150,000	$ 150,000	$ 150,000	$ 150,000
Marketing and Business Development	$ -	$ -	$ -	$ -	$ -
Contractor Costs	$ -	$ 529,158	$ 529,158	$ 529,158	$ 529,158
Inspection and Verification	$ -	$ 9,586	$ 9,586	$ 9,586	$ 9,586
Evaluation	$ -	$ 75,000	$ -	$ 75,000	$ -
Total	$ 50,000	$ 6,783,440	$ 6,708,440	$ 6,783,440	$ 6,708,440

Premium Efficiency Gas Appliances and Heating Equipment					
Customer Incentives	$ -	$ 472,954	$ 1,418,861	$ 1,418,861	$ 1,418,861
Administration and Management	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Total	$ 100,000	$ 659,271	$ 1,702,814	$ 1,627,814	$ 1,702,814
Commercial and Industrial Equipment Efficiency Upgrades					
Customer Incentives	$ -	$ -	$ 120,416	$ 270,936	$ 361,247
Administration and Management	$ -	$ 75,000	$ 100,000	$ 100,000	$ 100,000
Total	$ -	$ 125,000	$ 274,740	$ 505,666	$ 524,221
Municipal Facilities Comprehensive Efficiency Retrofit					
Customer Incentives	$ -	$ -	$ -	$ -	$ -
Administration and Management	$ -	$ 50,000	$ 50,000	$ 50,000	$ 50,000
On-site Technical Assessment	$ -	$ -	$ 615,600	$ 615,600	$ 615,600
Evaluation	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ 50,000	$ 667,139	$ 667,139	$ 667,139
High-Efficiency Construction					
Customer Incentives	$ -	$ -	$ 208,503	$ 521,257	$ 1,042,514
Administration and Management	$ -	$ 75,000	$ 75,000	$ 75,000	$ 75,000
Total	$ -	$ 125,000	$ 342,000	$ 667,501	$ 1,285,002
Commercial and Industrial Retrofit					
Customer Incentives	$ -	$ -	$ 107,036	$ 240,832	$ 321,109
Administration and Management	$ -	$ 50,000	$ 75,000	$ 75,000	$ 75,000
Total	$ -	$ 75,000	$ 236,361	$ 450,562	$ 459,083

Portfolio-wide Costs

Item	2010	2011	2012	2013	2014
Administration and Management	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Marketing and Business Development	$ 50,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Evaluation	$ -	$ -	$ -	$ -	$ 75,000
Total	$ 100,000	$ 200,000	$ 200,000	$ 200,000	$ 275,000

B. PGW's Spending and Savings Compared with Other Gas Utility DSM Portfolios

PGW's ambitious DSM investment portfolio follows in the footsteps of leading gas DSM program administrators around the U.S. and Canada. Figure 1 shows on a U.S. map where gas DSM programs are either active or planned.

Figure 1

STATES WITH ACTIVE AND PLANNED NATURAL GAS ENERGY EFFICIENCY PORTFOLIOS 2007 PROGRAM
61 ACTIVE AND 11 PLANNED IN 32 STATES AND CANADA

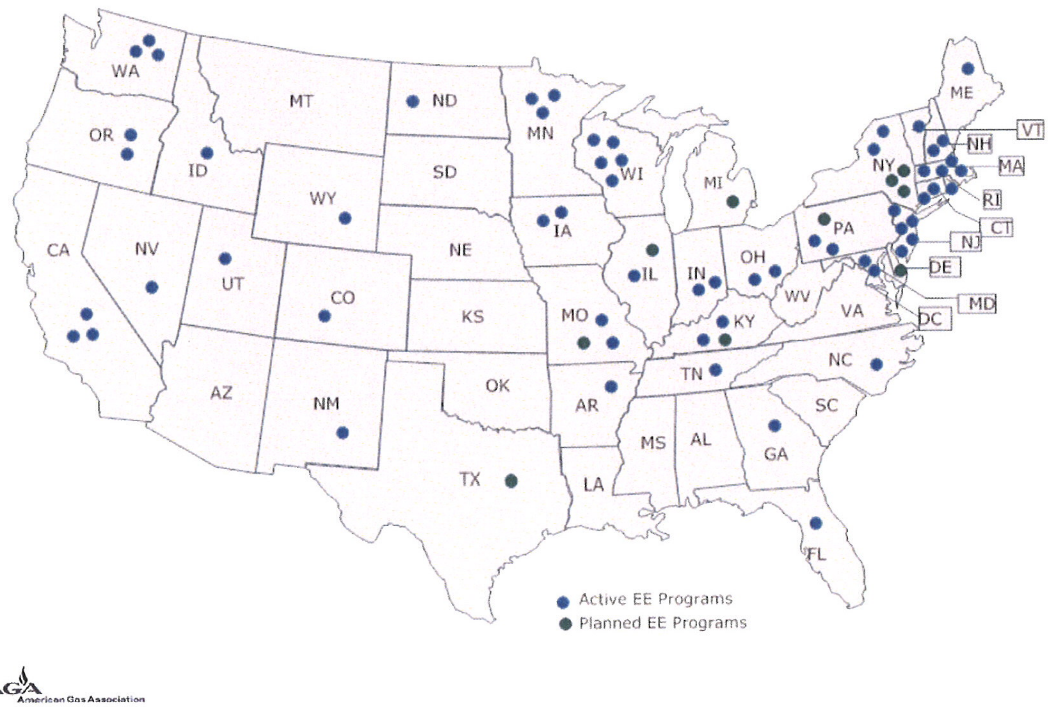


Table 4 presents utility gas DSM spending and savings by PGW and several industry leaders. Initially, PGW's spending is below average for the other utilities surveyed – at about \$0.02 per therm sold, with savings also below the average at about 0.39% of sales compared to the US/Canada average of 0.53% of sales. By the fifth year, however, PGW's spending and savings increase to more than twice the average spending and one and half times the average savings of other North American gas DSM portfolios.

Table 4

	Residential					Non-Residential					Total						
	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Spending per Lifetime Therm Saved	Spending per Therm Sold
								PGW PROJECTIONS									
Philadephia Gas Works																	
2010	$ 0.30	-	394	0.00%	$0.00	$ 0.05	0.00	114	0.00%	$0.00	$ 0.35	-	508	0.00%	$0.00	$0.00	$ 0.001
2011	$ 9.92	1.96	392	0.50%	$5.06	$ 0.48	0.00	114	0.00%	$0.00	$ 10.40	1.96	506	0.39%	$5.31	$0.54	$ 0.021
2012	$ 12.19	3.01	390	0.77%	$4.05	$ 1.69	0.33	113	0.29%	$5.13	$ 13.88	3.34	503	0.66%	$4.15	$0.42	$ 0.028
2013	$ 13.36	3.30	388	0.85%	$4.05	$ 2.46	0.55	113	0.49%	$4.45	$ 15.81	3.85	501	0.77%	$4.11	$0.42	$ 0.032
2014	$ 13.73	3.30	386	0.85%	$4.16	$ 3.25	0.77	112	0.68%	$4.23	$ 16.97	4.06	498	0.82%	$4.18	$0.43	$ 0.034
								ACTUAL									
NSTAR (Massachussets)																	
2004	$ 3.06	0.29	231	0.13%	$10.38	$ 1.02	0.44	239	0.18%	$2.32	$ 4.08	0.73	470	0.16%	$5.55	$0.57	$ 0.0087
2006	$ 2.98	0.28	193	0.14%	$10.75	$ 0.96	0.61	225	0.27%	$1.58	$ 3.94	0.89	418	0.21%	$4.45	$0.45	$ 0.0094
2007	$ 3.18	0.26	218	0.12%	$12.14	$ 1.04	0.51	249	0.21%	$2.02	$ 4.22	0.78	467	0.17%	$5.43	$0.55	$ 0.0090
Southern California Gas (California)																	
2006	$ 12.98	2.82	2,480	0.11%	$4.61	$ 13.22	8.81	3790	0.23%	$1.50	$ 26.20	11.62	6,270	0.19%	$2.25	$0.23	$ 0.0042
2007	$ 41.15	3.54	2,460	0.14%	$11.63	$ 24.74	23.28	3880	0.60%	$1.06	$ 65.89	26.81	6,340	0.42%	$2.46	$0.25	$ 0.0104
Enbridge (Canada & US)																	
2007		18.65	1,581	1.18%			14.63	2571	0.57%		$ 22.00	33.28	4,152	0.80%	$0.66	$0.07	$ 0.0053
Union Gas (Ontario)																	
2007	$ 4.09	4.70	1,031	0.46%	$0.87	$ 5.80	26.93	3869	0.70%	$0.22	$ 16.13	31.63	4,900	0.65%	$0.51	$0.05	$ 0.0033
Northern Utilities (New Hampshire)																	
2004	$ 0.29	0.01	17	0.07%	$25.65	$ 0.62	0.06	50	0.12%	$ 10.71	$ 0.91	0.07	67	0.10%	$ 13.13	$ 0.66	$ 0.0135
2005	$ 0.23	0.05	16	0.28%	$4.86	$ 0.41	0.03	49	0.06%	$ 14.62	$ 0.64	0.08	65	0.11%	$ 8.52	$ 0.43	$ 0.0098
2006	$ 0.20	0.05	14	0.34%	$4.22	$ 0.41	0.11	47	0.23%	$ 3.74	$ 0.61	0.16	61	0.26%	$ 3.89	$ 0.19	$ 0.0100
2007	$ 0.28	0.03	16	0.20%	$8.60	$ 0.43	0.10	55	0.17%	$ 4.55	$ 0.71	0.13	72	0.18%	$ 5.57	$ 0.28	$ 0.0099
EnergyNorth Natural Gas, Inc. (NH)																	
2004	$ 0.58	0.23	54	0.42%	$2.56	$ 0.35	0.18	69	0.27%	$10.71	$ 0.93	0.41	123	0.33%	$ 2.26	$ 0.66	$ 0.0076
2005	$ 0.98	0.30	61	0.49%	$3.23	$ 0.60	0.25	77	0.33%	$14.62	$ 1.58	0.56	139	0.40%	$ 2.84	$ 0.43	$ 0.0114
2006	$ 0.84	0.24	53	0.46%	$3.46	$ 0.90	0.34	72	0.47%	$3.74	$ 1.74	0.58	125	0.47%	$ 3.00	$ 0.19	$ 0.0140
2007	$ 1.01	0.23	48	0.48%	$4.45	$ 0.82	0.42	77	0.55%	$4.55	$ 1.83	0.65	125	0.52%	$ 2.83	$ 0.28	$ 0.0147
Vermont Gas Systems, Inc. (Vermont)																	
2003											$ 1.14	0.81	84	0.97%	$ 1.40	$0.14	$ 0.0136
2004											$ 1.12	0.57	86	0.66%	$ 1.97	$0.20	$ 0.0130
2005											$ 1.23	0.74	83	0.89%	$ 1.66	$0.17	$ 0.0148
2006	$ 0.77	0.25	29	0.87%	$3.09	$ 0.51	0.34	51	0.66%	$1.51	$ 1.28	0.59	80	0.73%	$ 2.18	$0.22	$ 0.0160
2007	$ 0.85	0.26	32	0.80%	$3.32	$ 0.66	0.53	56	0.94%	$1.25	$ 1.51	0.79	88	0.89%	$ 1.92	$0.20	$ 0.0171
2008	$ 1.00	0.31	32	0.96%	$3.22	$ 0.70	0.67	57	1.17%	$1.04	$ 1.70	0.98	90	1.10%	$ 1.73	$0.18	$ 0.0189
Iowa (All Investor Owned Utilities)																	
2001	$ 16.56	4.89	670	0.73%	$3.38	$ 1.45	0.89	404	0.22%	$1.63	$ 18.01	5.78	1,074	0.54%	$ 3.12	$0.32	$ 0.0168
2002	$ 14.98	4.14	679	0.61%	$3.62	$ 2.16	0.95	412	0.23%	$2.28	$ 17.14	5.09	1,091	0.47%	$ 3.37	$0.34	$ 0.0157
2003	$ 20.06	4.73	707	0.67%	$4.24	$ 2.18	1.47	420	0.35%	$1.48	$ 22.24	6.20	1,126	0.55%	$ 3.59	$0.37	$ 0.0197
2004	$ 20.47	5.30	654	0.81%	$3.86	$ 2.22	1.31	397	0.33%	$1.70	$ 22.69	6.61	1,051	0.63%	$ 3.43	$0.35	$ 0.0216
2005	$ 25.12	6.61	636	1.04%	$3.80	$ 3.18	2.11	405	0.52%	$1.51	$ 28.30	8.72	1,041	0.84%	$ 3.24	$0.33	$ 0.0272
2006	$ 27.42	6.92	587	1.18%	$3.96	$ 3.65	1.76	382	0.46%	$2.08	$ 31.07	8.68	969	0.90%	$ 3.58	$0.36	$ 0.0321
2007	$ 24.10	5.92	651	0.91%	$4.07	$ 4.34	2.14	521	0.41%	$2.03	$ 28.43	8.06	1,172	0.69%	$ 3.53	$0.36	$ 0.0243
Minnesota Energy Resources Corporation - PNG (Minnesota)																	
2006	$ 1.47	0.54			$2.70	$ 0.28	0.97			$0.29	$ 1.75	1.52			$1.16	$0.12	
2007	$ 1.11	0.42			$2.62	$ 0.45	0.77			$0.59	$ 1.56	1.19			$1.31	$0.13	
Xcel Energy (Minnesota)																	
2007	$ 3.25	1.48			$2.20	$ 2.51	7.41			$0.34	$ 5.76	8.88			$0.65	$0.07	
Great Plains Natural Gas Co. (Minnesota)																	
2006	$ 0.21	0.07			$3.02	$ 0.03	0.07			$0.45	$ 0.24	0.14			$1.74	$0.18	
2007	$ 0.20	0.05			$3.75	$ 0.04	0.12			$0.36	$ 0.24	0.18			$1.38	$0.14	
2008	$ 0.26	0.09			$2.77	$ 0.00	0.00			$0.54	$ 0.26	0.09			$2.71	$0.28	
CenterPoint Energy (Minnesota)																	
2006	$ 3.43	1.60			$2.15	$ 3.65	7.59			$0.48	$ 7.08	9.19			$0.77	$0.08	
2007	$ 3.81	1.65			$2.31	$ 3.42	6.60			$0.52	$ 7.23	8.25			$0.88	$0.09	
2008	$ 4.24	1.74			$2.44	$ 3.63	6.54			$0.56	$ 7.87	8.27			$0.95	$0.10	
Interstate Power and Lighting (Minnesota)																	
2005	$ 0.22	0.10			$2.26	$ 0.23	0.16			$1.44	$ 0.45	0.26			$ 1.74	$0.18	
2006	$ 0.19	0.08			$2.38	$ 0.29	0.16			$1.83	$ 0.48	0.24			$ 2.01	$0.20	
2007	$ 0.18	0.08			$2.25	$ 0.10	0.07			$1.45	$ 0.28	0.15			$ 1.87	$0.19	
2008	$ 0.19	0.07			$2.61	$ 0.17	0.11			$1.51	$ 0.36	0.18			$ 1.95	$0.20	
								AVERAGE OF ACTUAL EXPENDITURES AND SAVINGS									
	$ 6.94	**2.11**	**$ 503.33**	**0.55%**	**$ 4.64**	**$ 2.26**	**2.82**	**$ 633.07**	**0.39%**	**$ 2.78**	**$ 9.09**	**4.65**	**######**	**0.53%**	**$ 2.93**	**$ 0.273**	**$ 0.02**

	Residential					Non-Residential					Total						
	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Cost (Nominal $M)	Savings (Million Therms)	Sales (Million Therms)	Savings % of Sales	Spending per Annual Therm Saved	Spending per Lifetime Therm Saved	Spending per Therm Sold
								PLANNED									
Terasen (Canada)																	
2008	$ 7.46	0.93	771	0.12%	$7.99	$ 8.33	1.69	1074	0.16%	$4.92	$ 15.79	2.63	1,844	0.14%	$6.01	$0.61	$ 0.0086
2009	$ 7.59	1.18	771	0.15%	$6.42	$ 10.04	2.49	1074	0.23%	$4.03	$ 17.63	3.67	1,844	0.20%	$4.80	$0.49	$ 0.0096
2010	$ 6.65	0.95	771	0.12%	$6.98	$ 12.84	3.47	1074	0.32%	$3.70	$ 19.49	4.42	1,844	0.24%	$4.41	$0.45	$ 0.0106
Southern California Gas (California)																	
2008											$ 62.00	23.30	6,340	0.37%	$2.66	$0.27	$ 0.0098
2009											$ 73.20	27.20	6,340	0.43%	$2.69	$0.27	$ 0.0115
2010											$ 76.80	28.30	6,340	0.45%	$2.71	$0.28	$ 0.0121
2011											$ 82.20	29.90	6,340	0.47%	$2.75	$0.28	$ 0.0130
2012											$ 89.60	32.30	6,340	0.51%	$2.77	$0.28	$ 0.0141
2013											$ 100.30	35.80	6,340	0.56%	$2.80	$0.29	$ 0.0158
Mid-American (Iowa)																	
2009	$ 15.43					$ 3.55					$ 18.98	3.96	622	0.64%	$4.79	$0.49	$ 0.0305
2010	$ 16.95					$ 5.25					$ 22.20	4.74	624	0.76%	$4.68	$0.48	$ 0.0356
2011	$ 17.95					$ 5.48					$ 23.43	4.97	626	0.79%	$4.71	$0.48	$ 0.0374
2012	$ 19.14					$ 6.37					$ 25.51	5.25	629	0.84%	$4.86	$0.49	$ 0.0406
2013	$ 19.92					$ 6.48					$ 26.41	5.35	631	0.85%	$4.93	$0.50	$ 0.0418
Keyspan Long Island (New York)																	
2009	$ 1.78	0.22	407	0.05%	$8.01												
2010	$ 2.29	0.30	407	0.07%	$7.71												
2011	$ 3.46	0.37	407	0.09%	$9.47												
Keyspan New York (New York)																	
2009	$ 1.99	0.19	1,003	0.02%	$10.30												
2010	$ 3.40	0.35	1,003	0.04%	$9.64												
2011	$ 5.76	0.66	1,003	0.07%	$8.79												
Central Hudson Gas & Electric (New York)																	
2009						$ 0.05	0.01			$7.61							
2010						$ 0.17	0.03			$6.43							
2011						$ 0.17	0.03			$6.43							
Consolidated Edison of New York (New York)																	
2009						$ 0.37	0.04			$9.13							
2010						$ 4.17	0.80			$5.22							
2011						$ 6.05	1.14			$5.30							
NYSERDA FlexTech (New York)																	
2010											$ 1.33	2.37			$0.56	$0.06	
2011											$ 1.70	2.85			$0.59	$0.06	
2012											$ 0.81	1.18			$0.68	$0.07	
2013											$ 0.40	1.18			$0.34	$0.03	
National Grid NY and National Grid Commercial (New York)																	
2009	$ 0.76	1.78			$0.43	$ 3.76	0.83			$4.54	$ 4.52	2.61			$1.73	$0.18	
2010	$ 2.69	0.65			$4.12	$ 12.10	2.45			$4.95	$ 14.79	3.10			$4.77	$0.49	
2011	$ 2.69	0.65			$4.12	$ 12.08	2.45			$4.94	$ 14.77	3.10			$4.77	$0.49	
								AVERAGE OF PROJECTED EXPENDITURES AND SAVINGS									
	$ 8.16	**0.57**	**$ 705.11**	**0.06%**	**$ 6.95**	**$ 4.72**	**0.86**	**#DIV/0!**	**#DIV/0!**	**$ 6.06**	**$ 35.50**	**12.08**	**######**	**0.61%**	**$ 2.99**	**$ 0.305**	**$ 0.02**
								AVERAGE OF ACTUAL AND PROJECTED EXPENDITURES AND SAVINGS									
	$ 7.00	**1.75**	**$ 577.04**	**0.43%**	**$ 5.32**	**$ 3.39**	**2.70**	**$ 768.25**	**0.39%**	**$ 3.45**	**$ 16.85**	**6.88**	**######**	**0.53%**	**$ 3.00**	**$ 0.287**	**$ 0.02**

IV. PGW DSM PORTFOLIO IMPLEMENTATION

This section addresses three crucial aspects of PGW's management of its gas DSM programs:

- Program administration and management
- Program integration with other programs
- Staged program implementation

A. Program Administration and Management

Program administration and management refers to the set of functions associated with designing, developing, planning program services and activities; contractor supervision; data management and reporting, installation verification of high-efficiency gas measures through the various DSM programs.

1. Implementation Management

PGW is responsible for achieving the performance goals of its DSM investment portfolio, according to the guiding principles for achieving the core objectives of the plan. The scope of PGW's implementation management responsibilities encompasses:

- Customer recruitment and intake
- Opportunity assessment
- Measure installation
- Financial incentive processing
- Inspection and verification
- Data management

2. Staffing and Sourcing

PGW personnel will manage the implementation of energy-efficiency programs. Installation of efficiency measures will be done by independent contractors that PGW will select through competitive, public RFP solicitation. This model builds on PGW's successful experience managing the delivery of its low-income retrofit program to approximately 2,500 customers per year. PGW will also retain outside experts to assist it in preparing specifications for implementation contractor solicitation, assessing competing bids, structuring contracts, and establishing performance goals.

3. Program Marketing and Business Development

PGW will be responsible for all outreach to customers and to members of the supply chain for gas appliances and equipment such as vendors, wholesalers, and manufacturers. A critical component of successful marketing will be market research. PGW will rely on in-house personnel as well as contractors as necessary to develop and execute marketing strategies to maximize participation. PGW will work closely with retrofit program implementation contractors to maximize individual customers' trust and acceptance. PGW will also work with civic and other organizations on coordinated campaigns to maximize participation in targeted areas.

4. Tracking and Reporting

PGW will expand its existing information management systems to track the cost and performance information.

PGW will file regular reports on spending, participation, energy savings, and benefits. The following table presents the information PGW proposes to track and report periodically to the PUC.

Figure 2: Sample Program Annual Report

Program Name

Program Start Date: 1/1/1900
Gross to Net Adjustment Factor: 0%

	Actual Previous Program Year	Actual Current Program Year	Projected Program Year	Projected Next Program Year	Total Program Reported to Date [22]
PARTICIPATION					
Pending [1]	-	-	n/a	n/a	n/a
Analyses/Audits with No Installs [2]	-	-	n/a	n/a	n/a
Analyses/Audits [3]	-	-	-	-	-
Customers with Installations [4]	-	-	-	-	-
COSTS					
Utility Costs [12]	$ -	$ -	$ -	$ -	$ -
Customer Incentives [5]	$ -	$ -	$ -	$ -	$ -
Administration and Management [6]	$ -	$ -	$ -	$ -	$ -
Marketing and Business Development [7]	$ -	$ -	$ -	$ -	$ -
Contractor Costs [8]	$ -	$ -	$ -	$ -	$ -
Inspection and Verification [9]	$ -	$ -	$ -	$ -	$ -
On-site Technical Assessment [10]	$ -	$ -	$ -	$ -	$ -
Evaluation [11]	$ -	$ -	$ -	$ -	$ -
Participant Costs [13]	$ -	$ -	$ -	$ -	$ -
Total [14]	$ -	$ -	$ -	$ -	$ -
BENEFITS [15]					
Annualized BBtu [16]	-	-	-	-	-
Lifetime BBtu [17]	-	-	-	-	-
Peak Day BBtu [18]	-	-	-	-	-
Annualized BBtu [19]	-	-	-	-	-
Weighted Lifetime (years) [20]	-	-	-	-	-

Program Year Activity

End-Use Breakdown	Annualized BBtu Saved [16]	Peak Day BBtu Savings [18]	Number of Customers with Installations [21]	Weighted Lifetime [20]
Heating				
Water Heating				
Air Infiltration				
Heat Recovery				
Shell (envelope)				
Process				
Total				

Descriptions of Fields

[1]	Number of customers who requested service who are still waiting to receive it on December 31 of the year specified in the column heading.
[2]	Number of customers who had analyses or audits completed during the reporting year, but who have not yet had verified installations by December 31 of the year specified in the column heading.
[3]	Number of customers who had analyses or audits completed between January 1 and December 31.
[4]	Number of customers with verified installations in the period January 1 to December 31.
[5]	Incentive payments to customers and/or trade allies, excluding direct installation costs
[6]	Any costs incurred by the utility not directly attributed to items [7]. [8], [9], [10], and [11]
[7]	Costs associated directly with the marketing and business development activies of the program
[8]	Non-incentive payments to third-party contractors, including direct installation.
[9]	Payments to utlity staff or contractors for performing analyses, audits, inspections, and verifications Also includes cost for energy ratings.
[10]	Costs incurred from in-depth onsite potential studies. Applies to Municipal and C&I Retrofit programs
[11]	Evaluation costs, excluding tracking and reporting expenses.
[12]	Sum of items [5] through [11]
[13]	Customer expenditures, including loan amount
[14]	[12] + [13]
[15]	Savings adjusted by the free rider percentage where applicable.
[16]	Estimated annual savings for measures installed and verified during the reporting year for a one-year period.
[17]	The lifetime estimated BBtu savings for measures installed and verified during the reporting year. Estimated annualized savings times the estimated life of the measure.
[18]	Estimated impact of measure on peak day. Since measures are installed throughout the year, does not reflect Mcf avoided on peak day of the reporting year.
[19]	Total Mcf saved divided by the total participants.
[20]	Average lifetime, in years, of measures in the program weighted by savings.
[21]	Number of customers with verified installations of measures within that end-use. Where a customer had more than one measure installed within an end-use, i.e. both wall and attic installation within the "shell" end-use, they are counted only once.
[22]	Cumulative activity from program start date until December 31. Individual program start dates are listed on the upper right-hand corner of each summary sheet.

5. Measurement, Verification and Evaluation

PGW will apply the same approach to measurement, verification, and evaluation that it currently employs in the administration of the low-income program.

PGW will establish a technical reference manual codifying and updating methods and assumptions for calculating savings from the full array of prescriptive gas efficiency measures. Specialized retrofit projects, especially for commercial and industrial projects, will be characterized on a customized basis in terms of their lifetime costs and performance. PGW will use these characterizations to calculate and track the economic benefits and costs of both prescriptive and customized efficiency projects.

PGW will also verify that measures are actually installed as recommended and analyzed.

PGW has conducted extensive evaluation of its low-income program, which is delivered by two implementation contractors, DMC/Honeywell and the Energy Coordination Agency of Philadelphia. PGW will continue to use the results of independent evaluation to update savings estimates and redirect program activities. PGW will also develop a program evaluation plan for the entire portfolio to be submitted with its detailed work plans following Commission approval of this DSM plan. The program timetable presented in Section IV.C indicates the timing of the evaluations PGW plans to undertake starting in 2011; the program budgets in Section III.A, above, provide the funds PGW estimates will be required for these studies.

Primary evaluation issues to be addressed in the initial set of evaluations will include:

- Costs and savings from enhanced efficiency services in the both the residential retrofit programs
- Effectiveness of PGW's proposed financial strategies in attracting participants in the non-low income retrofit program
- Effectiveness of PGW's end-user and upstream financial strategies in raising the market penetration of and lowering the price premium for the highest-efficiency heating equipment

In 2014, PGW proposes to conduct a portfolio-wide evaluation of its implementation of its DSM portfolio. This will include a comparative analysis of PGW's performance against that of its peers.

B. Integrated Approach to Customer Efficiency Investment

To maximize value from its gas DSM portfolio, PGW will take advantage of incremental opportunities to save gas as well as other resource savings, including electricity. Decades of DSM program experience prove that failure to do so would lead to missed opportunities, duplication of effort, needlessly high costs, and customer confusion. Incremental energy saving opportunities will also reduce the customer's carbon footprint and increase the ability of PGW customers to pay their gas bills on time and in full. For example, improving building thermal performance will save heating gas as well as electricity used for cooling. Especially for residential customers and small commercial customers, it makes the most sense for PGW or, if feasible, PGW and other partners, to combine forces to offer customers one-stop shopping for efficiency measures addressing electricity and gas. Consequently, PGW will seek to integrate gas efficiency opportunities with other non-gas efficiency efforts. Any cost sharing between PGW and other organizations will be guided by the value of gas benefits relative to the value of other resource savings generated by the programs.

PGW will assume lead responsibility for implementing comprehensive retrofits for City residents and in City-owned and/or managed facilities. PGW will explore the feasibility of partnering with other programs designed and implemented to achieve cost-effective efficiency savings in residential and business construction and in comprehensive business retrofits, but will administer these programs independently, if necessary. PGW will also explore the feasibility of coordinating its residential appliance and heating and business equipment efficiency programs with other programs aimed at the same markets. While PGW believes that such partnering may provide enhanced efficiencies and benefits, this plan does not assume or depend upon cooperation with other organizations.

1. Electric efficiency measures to be integrated into PGW programs

Residential retrofit

PGW plans on integrating two types of electric efficiency measures into its Comprehensive Residential Heating Retrofit and Enhanced Low-Income Retrofit Programs.

In conjunction with its Heating Retrofit activities, PGW will provide direct installation of full range of latest high-efficiency lighting products available in each participating home. The average American household has 30 or more lighting fixtures. PGW contract installers (who will also be doing the heating retrofits) will be trained to install as many compact fluorescent lamps as the customer will accept. The installer will leave behind at least one "multi-pack" of replacement lamps to ensure that customers have ready access to replacement lamps, pending roll-out of a retail efficiency products program by others. A key aspect of this proposal is that, because the net incremental cost of the CFL installations is so low, it will permit the delivery of electric energy efficiency measures to a market segment that it might not otherwise be cost-effective to address.

Lighting direct installation will lead to substantial economic and environmental benefits. Table 5 provides a breakdown of gas and electricity benefits for the comprehensive residential retrofit program.

Table 5

Comprehensive Residential Heating Retrofit: Gas Savings Compared to Electric Savings

	Gas	Electric
Present Value of Benefits ($2009)	$28,665,111	$ 9,013,992
Present Value of Costs ($2009)	$10,950,799	$ -
Present Value of Net Benefits ($2009)	$17,714,311	$ 9,013,992
Benefit-Cost Ratio	2.62	0.00
Cumulative Annual Energy Saved in 5th Year (Net of Freeriders)	3.7 Million Therms	21.1 GWh

Electric energy saved measured at generation.

Residential appliances and heating equipment

In addition to incentives for high-efficiency gas appliances and equipment, PGW will assist customers find other programs that may provide supplemental incentives for new purchases of:

- High-efficiency furnaces with ECMs (electrically-commutated motors)
- High-efficiency clothes washers

Prescriptive cost-effectiveness analysis will be performed in advance to establish cost-effectiveness of high-efficiency gas equipment.

Municipal facilities retrofit

PGW will help the City identify other programs that may offer electric efficiency incentives with the goal of providing immediate positive cashflow for comprehensive packages of the following technologies:

- Lighting retrofit (Super T8, T5, LED fixtures; controls; lighting system redesign)
- HVAC retrofit (early retirement; unitary to central conversions; proper sizing of equipment to match load; distribution controls)
- Refrigeration (early retirement, supplemental controls)

PGW will work with the City and state and financial institutions that provide energy loans to structure short-term financing for the balance of capital investment required (gas measures plus electric efficiency investment costs not covered by other incentives).

All efficiency measures (gas and electric) will be subjected to individualized cost-effectiveness analysis to direct investment toward economically optimal packages. The cost-effectiveness analysis for this program does not include the effects of electric efficiency investment, which will increase the net benefits expected from the program.

2. Gas efficiency measures ideally integrated into other programs

In three markets, electricity savings potential is as large as or larger than gas efficiency potential. These are high-efficiency construction (residential and commercial), and commercial and industrial retrofit. PGW plans to work closely on devising financial incentives that address both gas and electric efficiency measures as a package in construction, renovation, and retrofit of commercial and industrial properties, and in new residential construction. PGW will explore the potential to integrate with other parties and programs, but if agreement on integration is not reached, PGW will design the incentives for the gas-saving measures based partly on the incentives and benefits of the related electric-saving equipment.

3. Coordinating with other programs

PGW will investigate opportunities to coordinate the design and implementation of programs promoting high-efficiency appliances and heating equipment with other programs. While not as closely linked as in other markets, PGW programs and other programs addressing electric efficiency should at least have consistent efficiency performance thresholds that do not favor one energy source over the other. PGW will explore the feasibility of coordination with other programs promoting residential appliance and heating equipment efficiency upgrades, and for commercial and industrial equipment efficiency upgrades.

C. Program Staging

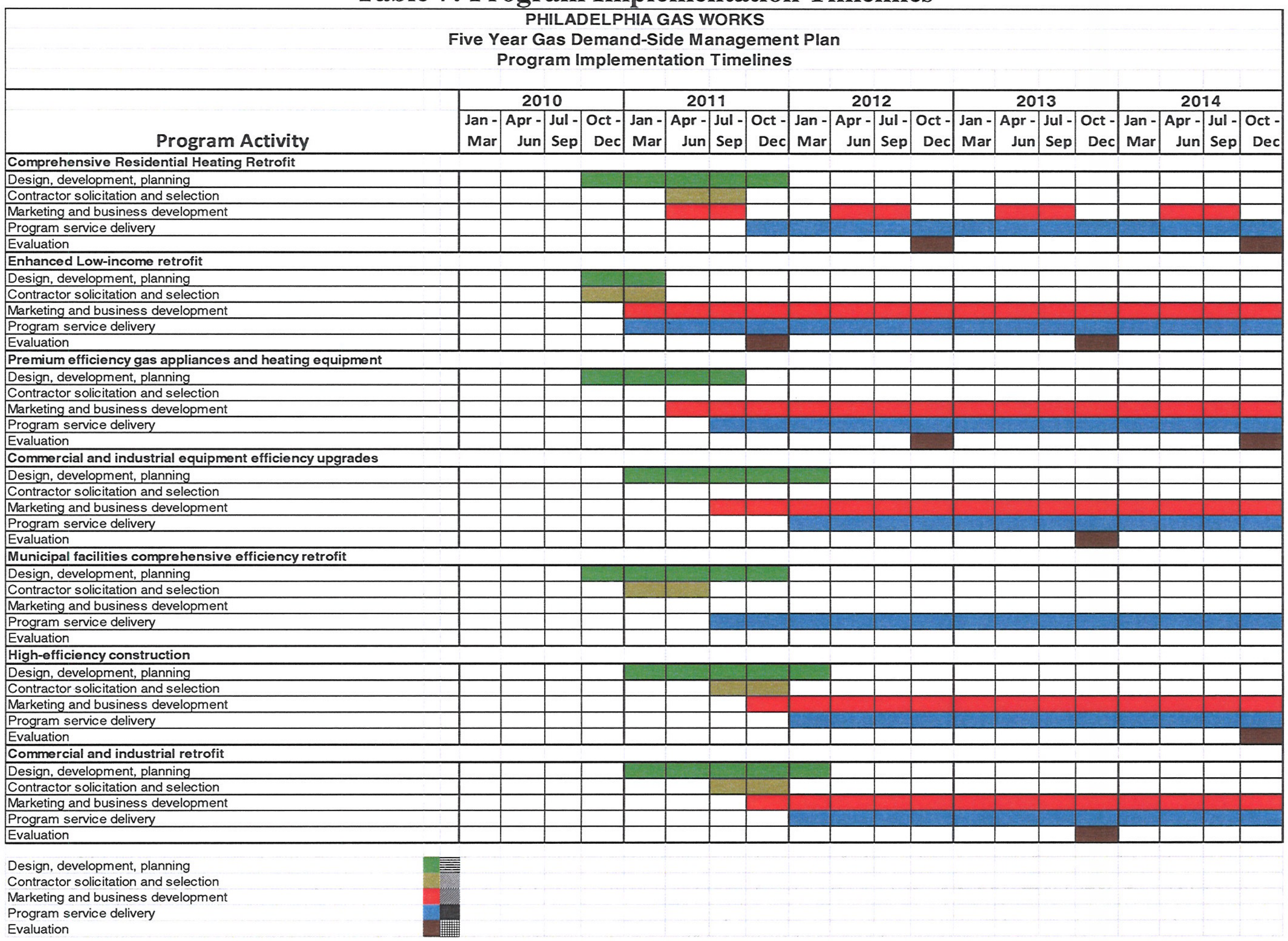
As shown in Table 3, PGW plans to scale up DSM spending rapidly and substantially. Fortunately, the bulk of the expansion in terms of money and savings is scaling up and fine-tuning PGW's successful low-income retrofit program. 2011 will therefore focus on scaling up the low-income program. 2011 will also involve designing and launching the comprehensive residential retrofit program, and identifying opportunities for comprehensive efficiency retrofits in City facilities. All programs scale up to their maximum participation rates in 2014. Table 6 shows the relative pace of implementation in each year.

Table 6

PHILADELPHIA GAS WORKS Five Year Gas Demand-Side Management Plan PROGRAM INPUTS						
		Staging % of Maximum Customer Participation in Year				
PROGRAM	Maximum Annual Customer Participation	2010	2011	2012	2013	2014
Comprehensive Residential Heating Retrofit	7,020	0%	50%	75%	100%	100%
Enhanced Low-income Retrofit	3,834	0%	100%	100%	100%	100%
Premium Efficiency Gas Appliances and Heating Equipment	13,581	0%	33%	100%	100%	100%
Commercial and industrial equipment efficiency upgrades	519	0%	0%	33%	75%	100%
Municipal Facilities Comprehensive Efficiency Retrofit	62	0%	0%	100%	100%	100%
High-efficiency Construction	1,700	0%	0%	20%	50%	100%
Commercial and Industrial Retrofit	519	0%	0%	33%	75%	100%

Table 7 offers a more detailed look at each program's time table.

Table 7: Program Implementation Timelines



V. ENERGY, ECONOMIC, AND ENVIRONMENTAL IMPACTS OF PGW'S DSM PLAN

This section provides more detail on PGW's estimates of energy savings from its planned DSM portfolio, and their monetary, employment, and pollution impacts.

A. Energy Savings

Table 8 shows the annual gas and electricity savings PGW projects from its DSM portfolio.

Table 8

PHILADELPHIA GAS WORKS
GAS DSM PORTFOLIO
GAS AND ELECTRICITY SAVINGS BY YEAR

Program Year:	1	2	3	4	5
Year:	2010	2011	2012	2013	2014
- Gas					
Incremental annual BBtu Gas Saved (Net)	0	196	334	385	406
Cumulative annual BBtu Saved (Net)	0	196	530	915	1,321
Electricity					
Incremental annual MWh Saved (Net at meter)	0	5,730	7,130	8,530	8,530
Cumulative annual MWh Saved (Net, at meter)	0	5,730	12,860	21,390	29,920
Incremental annual Summer kW Saved (Net at m	0	1,598	2,016	2,433	2,433
Cumulative annual Summer kW Saved (Net, at m	0	1,598	3,614	6,048	8,481

Gas savings are significant. As shown earlier in Table 4, the annual incremental savings increase fivefold between 2011 and 2014. Electricity savings from air conditioning and lighting direct installation as part of the residential retrofit programs are small but extremely valuable, as shown below.

B. Cost Savings

The benefits of PGW's DSM program are the avoided costs of gas and other resource savings. This section presents the monetary values PGW applied to these resource savings to estimate gas DSM benefits. It also assesses program cost-effectiveness from the perspective of the economy at large and from the vantage point of energy ratepayers. This section presents PGW's estimates of the rate and bill impacts from the plan over time.

1. Avoided supply costs

Table 9 presents the unit values of resources PGW estimated for gas, electricity, and water savings by year. PGW estimated the value of three gas-saving load profiles: space heating, water heating, and base use.

Table 9

All Avoided Costs Are in Constant 2009 Dollars

	Electric Avoided Costs including losses		Natural Gas Avoided Costs			Other Resource Avoided Costs
Period:	All-Year Energy	Summer GenerationC apacity	NG Base	NG Space Heat	NG DHW	Water
Units:	$/kWh	$/kW-yr	$/MMBtu	$/MMBtu	$/MMBtu	$/gal
2010	0.0602	85.05	7.34	8.74	7.69	$ 0.0100
2011	0.0632	66.60	7.46	8.84	7.80	$ 0.0100
2012	0.0640	53.12	7.42	8.76	7.75	$ 0.0100
2013	0.0641	57.52	7.39	8.71	7.72	$ 0.0100
2014	0.0656	64.00	7.42	8.75	7.75	$ 0.0100
2015	0.0679	64.00	7.49	8.83	7.83	$ 0.0100
2016	0.0705	64.00	7.63	8.98	7.97	$ 0.0100
2017	0.0738	64.00	7.84	9.21	8.18	$ 0.0100
2018	0.0775	64.00	8.10	9.51	8.45	$ 0.0100
2019	0.0813	64.00	8.24	9.66	8.60	$ 0.0100
2020	0.0816	64.00	8.23	9.65	8.59	$ 0.0100
2021	0.0806	64.00	8.27	9.69	8.62	$ 0.0100
2022	0.0826	64.00	8.37	9.80	8.73	$ 0.0100
2023	0.0850	64.00	8.65	10.12	9.02	$ 0.0100
2024	0.0902	64.00	8.99	10.49	9.36	$ 0.0100
2025	0.0947	64.00	9.30	10.83	9.68	$ 0.0100
2026	0.0992	64.00	9.60	11.17	9.99	$ 0.0100
2027	0.1037	64.00	9.86	11.46	10.26	$ 0.0100
2028	0.1077	64.00	10.06	11.68	10.46	$ 0.0100

Assumptions and calculations behind these estimates are presented in Section VII.E, below.

2. Net economic benefits of PGW's DSM Plan

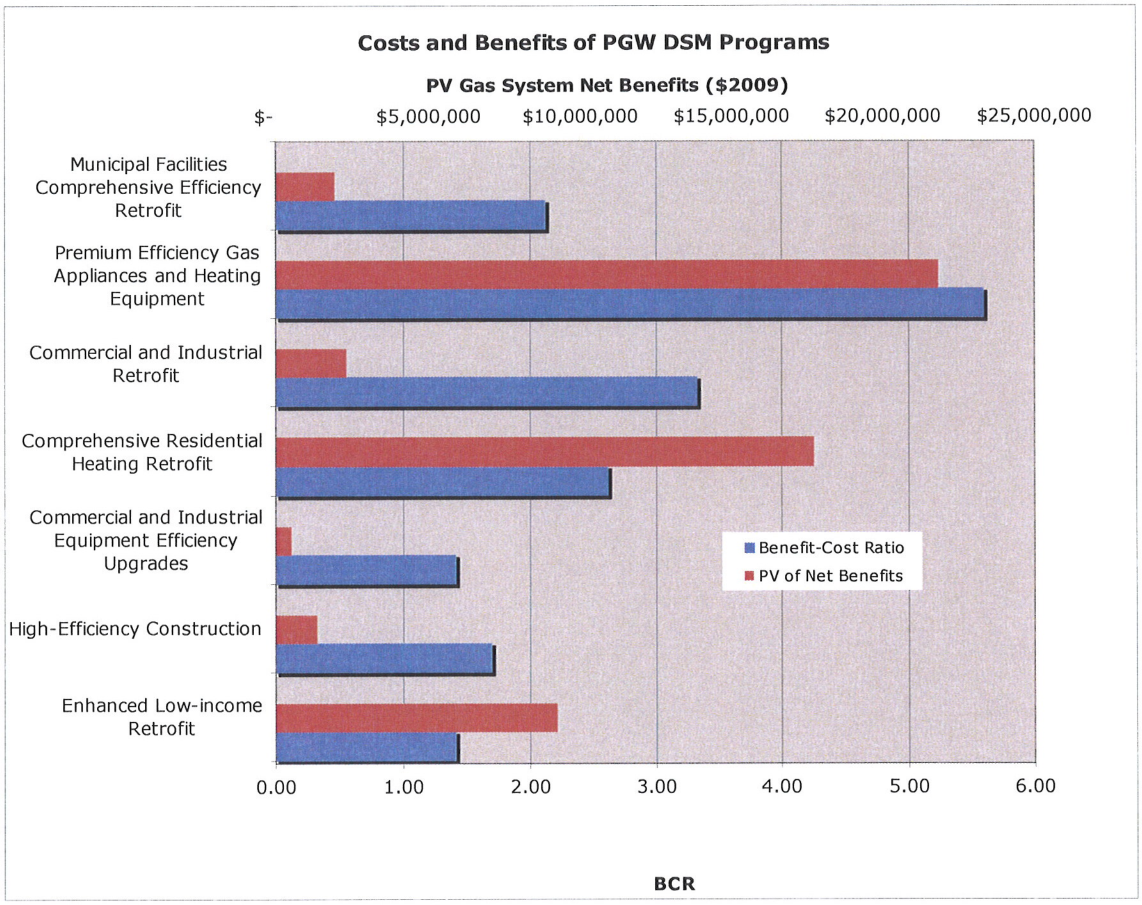
PGW analyzed the benefits and costs of its proposed DSM programs from two perspectives. The first and primary test of cost-effectiveness is the total resource cost (TRC) perspective. It measures the gain in economic welfare from making the investment by comparing the present worth of resource benefits with the present worth of resource costs of the DSM plan. Total resource benefits are the avoided gas, electric, and water costs. Total resource costs consist of PGW's expenditures on program measures and on "non-measure," i.e., administration costs. They also include the customers' direct contribution to the efficiency investments, that is, the portion of efficiency measure costs not covered by PGW program expenditures.

PGW also analyzed benefits and costs from the perspective of the utility system. This calculation ignores the costs not borne or avoided by PGW, i.e., the costs participants pay themselves. While not a true indicator of economic merit, it does provide a reasonable indication of the extent to which the investment represents a good use of ratepayer funds. We provide results for the gas system alone and for the electricity system from electric efficiency measures. The electric system analysis does not reflect any electric utility contribution toward the administrative costs of the residential programs. Nor does the analysis reflect any total resource benefits or costs of other electric efficiency measures besides lighting and air conditioning in the residential retrofit programs, or any electric efficiency measures in the commercial and industrial programs.

Two measures of cost-effectiveness are presented. The net benefits are the difference between benefits and costs. This is the most indicative of economic merit, since it calculates the magnitude of the welfare gain. Maximizing net benefits from the portfolio maximizes customer value. The benefit/cost ratio (BCR) is also presented as a rough indicator of relative value. Maximizing the BCR does not necessarily lead to maximum customer value; doing so would automatically leave behind cost-effective savings, i.e., gas savings that cost less than the supply they avoid.

Figure 3 graphically depicts the net benefits of each program. The maroon bar is the magnitude of net benefits for each program, reading off the top horizontal scale. The blue bar is the program's BCR, read off the bottom horizontal scale.

Figure 3



Figures 4 and 5 depict benefits and costs of the residential and nonresidential programs, respectively. In each figure, the stacked vertical bars represent the sum of each sector's measure and non-measure costs, reading off the left-hand vertical scale. The blue area indicates the cumulative value of these investments over the lifetime of the measures installed, reading off the right-hand vertical scale.

Figure 4

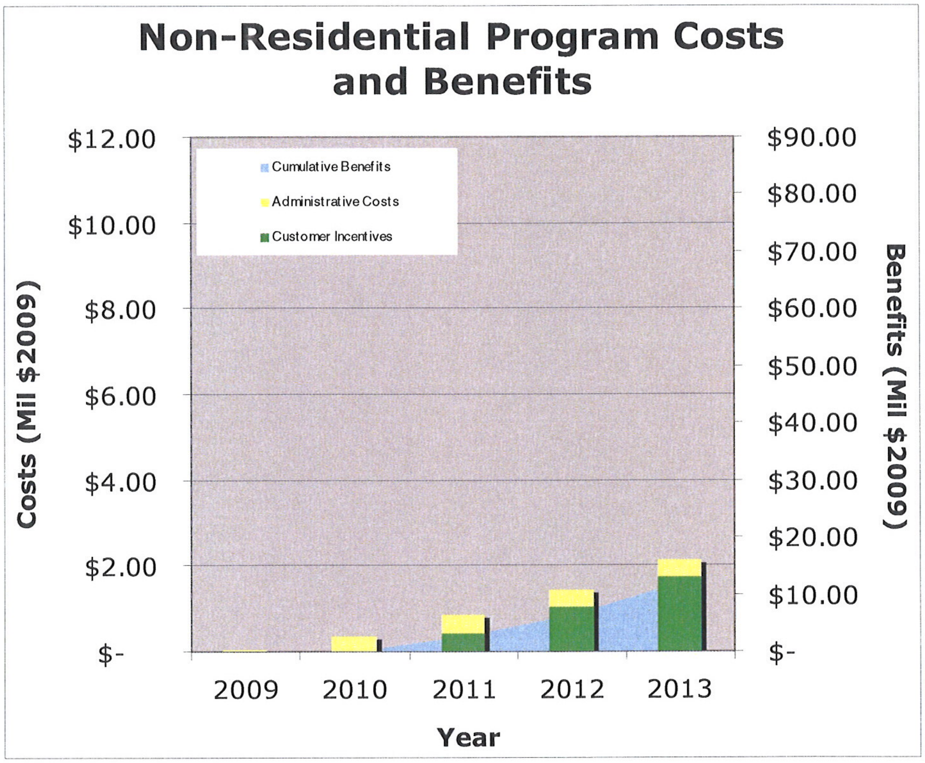


Figure 5

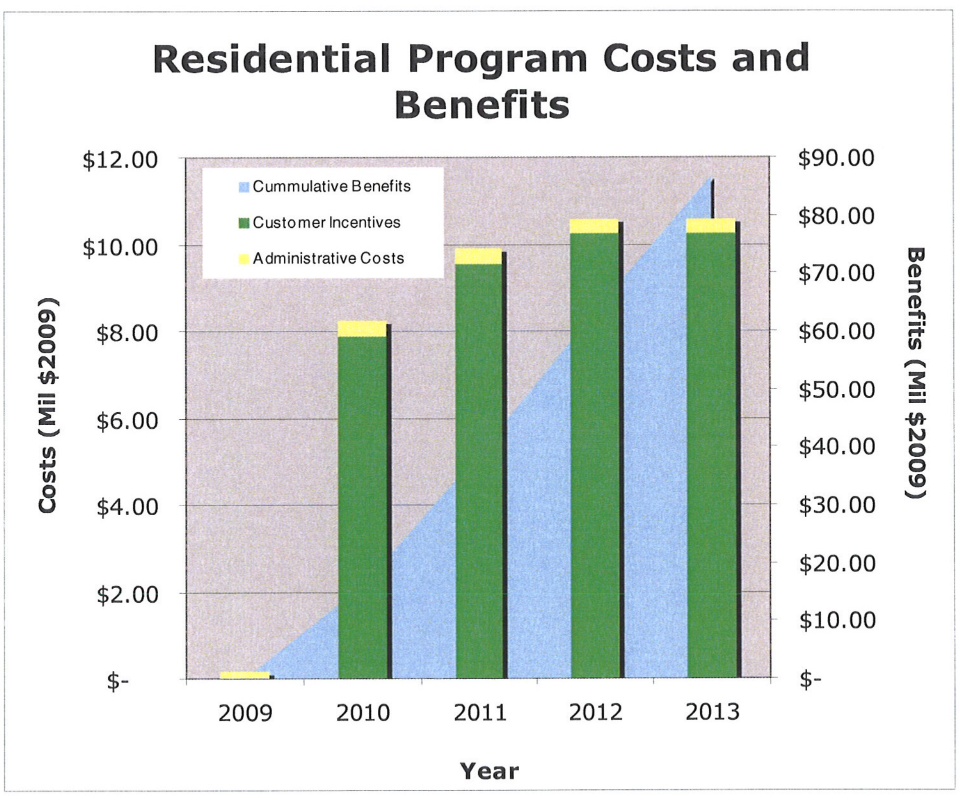


Table 10 projects and compares the present value benefits and costs of each program under four cost-effectiveness perspectives.

Table 10

PHILADELPHIA GAS WORKS
DSM PROGRAM PLAN
COST-EFFECTIVENESS ANALYSIS

	Total Resource					Electric Energy System				Gas Energy System					Electric & Gas Energy System			
	Present Value		PV of Net Benefits	Benefit-Cost Ratio	Levelized Cost	Present Value		PV of Net Benefits	Benefit-Cost Ratio	Present Value		PV of Net Benefits	Benefit-Cost Ratio	Levelized Cost	Present Value		PV of Net Benefits	Benefit-Cost Ratio
	Benefit [2]	Cost [3]	[4]	[5]	$/MMBTU	Benefit [6]	Cost [7]	[8]	[9]	Benefit [10]	Cost [11]	[12]	[13]	$/MCF	Benefit [14]	Cost [15]	[16]	[17]
Portfolio Total	$113,157,561	$57,808,244	$55,349,317	1.96	5.33	$14,491,497	-	$14,491,497	-	$98,666,064	$44,687,579	$53,978,485	2.21	4.11	$113,157,561	$44,687,579	$68,469,983	2.53
Non-Measure Costs		$11,302,468					$0				$11,302,468					$11,302,468		
Total Measure Costs	$113,157,561	$46,505,776	$66,651,785	2.43	4.33	$14,491,497	-	$14,491,497	-	$98,666,064	$33,385,111	$65,280,953	2.96	3.11	$113,157,561	$33,385,111	$79,772,451	3.39
Program																		
Comprehensive Residential Heating Retrofit																		
Program Total	$37,679,103	$21,617,885	$16,061,218	1.74	7.14	$9,013,992	-	$9,013,992	-	$28,665,111	$10,950,799	$17,714,311	2.62	3.59	$37,679,103	$10,950,799	$26,728,304	3.44
Non-Measure Costs		$3,599,166					$0				$3,599,166					$3,599,166		
Total Measure Costs	$37,679,103	$18,018,718	$19,660,385	2.09	6.01	$9,013,992	-	$9,013,992	-	$28,665,111	$7,351,633	$21,313,477	3.90	2.45	$37,679,103	$7,351,633	$30,327,470	5.13
Enhanced Low-income Retrofit																		
Program Total	$37,044,268	$21,972,192	$15,072,076	1.69	6.58	$5,477,505	-	$5,477,505	-	$31,566,763	$22,316,612	$9,250,151	1.41	6.69	$37,044,268	$22,316,612	$14,727,656	1.66
Non-Measure Costs		$2,575,906					$0				$2,575,906					$2,575,906		
Total Measure Costs	$37,044,268	$19,396,286	$17,647,982	1.91	5.85	$5,477,505	-	$5,477,505	-	$31,566,763	$19,740,705	$11,826,058	1.60	5.95	$37,044,268	$19,740,705	$17,303,563	1.88
Premium Efficiency Gas Appliances and Heating Equipment																		
Program Total	$26,519,663	$4,740,331	$21,779,332	5.59	1.50	-	-	-	-	$26,519,663	$4,740,331	$21,779,332	5.59	1.50	$26,519,663	$4,740,331	$21,779,332	5.59
Non-Measure Costs		$930,799					$0				$930,799					$930,799		
Total Measure Costs	$26,519,663	$3,809,532	$22,710,131	6.96	1.22	-	-	-	-	$26,519,663	$3,809,532	$22,710,131	6.96	1.22	$26,519,663	$3,809,532	$22,710,131	6.96
Commercial and Industrial Equipment Efficiency Upgrades																		
Program Total	$1,656,514	$1,366,816	$289,698	1.21	6.92	-	-	-	-	$1,656,514	$1,170,821	$485,6921.	41	5.90	$1,656,514	$1,170,821	$485,692	1.41
Non-Measure Costs		$582,838					$0				$582,838					$582,838		
Total Measure Costs	$1,656,514	$783,978	$872,536	2.11	4.06	-	-	-	-	$1,656,514	$587,983	$1,068,530	2.82	3.05	$1,656,514	$587,983	$1,068,530	2.82
Municipal Facilities Comprehensive Efficiency Retrofit																		
Program Total	$3,676,093	$3,290,862	$385,230	1.12	8.34	-	-	-	-	$3,676,093	$1,734,161	$1,941,932	2.12	4.27	$3,676,093	$1,734,161	$1,941,932	2.12
Non-Measure Costs		$1,734,161					$0				$1,734,161					$1,734,161		
Total Measure Costs	$3,676,093	$1,556,702	$2,119,391	2.36	4.06	-	-	-	-	$3,676,093	-	$3,676,093	-	-	$3,676,093	-	$3,676,093	-
High-Efficiency Construction																		
Program Total	$3,268,894	$1,925,587	$1,343,307	1.70	5.61	-	-	-	-	$3,268,894	$1,925,587	$1,343,307	1.70	5.61	$3,268,894	$1,925,587	$1,343,307	1.70
Non-Measure Costs		$552,982					$0				$552,982					$552,982		
Total Measure Costs	$3,268,894	$1,372,605	$1,896,289	2.38	4.06	-	-	-	-	$3,268,894	$1,372,605	$1,896,289	2.38	4.06	$3,268,894	$1,372,605	$1,896,289	2.38
Commercial and Industrial Retrofit																		
Program Total	$3,313,027	$2,040,365	$1,272,662	1.62	5.22	-	-	-	-	$3,313,027	$995,061	$2,317,966	3.33	2.51	$3,313,027	$995,061	$2,317,966	3.33
Non-Measure Costs		$472,409					$0				$472,409					$472,409		
Total Measure Costs	$3,313,027	$1,567,956	$1,745,071	2.11	4.06	-	-	-	-	$3,313,027	$522,652	$2,790,375	6.34	1.35	$3,313,027	$522,652	$2,790,375	6.34
Portfolio-wide Costs																		
Program Total	-	$854,207	$(854,207)	-	#DIV/0!	-	-	-	-	-	$854,207	$(854,207)	-	#DIV/0!	-	$854,207	$(854,207)	-
Non-Measure		$854,207					$0				$854,207					$854,207		

3. DSM portfolio bill and rate impacts

The net benefits of PGW DSM investment are realized over the entire life expectancy of the efficiency measures installed, which averages 15-20 years. The costs are incurred during the next five years. Recovering the portfolio costs over a smaller sales base puts upward pressure on bills and rates in the early years; after that, the benefits of the gas savings continue for the next 15 years in the form of lower bills.

PGW analyzed the near-term impact on rates and bills from its gas DSM plan. Average bills for all customers combined (participants and nonparticipants) will rise in the early years and then generally decline thereafter. For example, average bills for municipal customers rise the most, by 3.7% in 2013, and then fall to 2.3% in 2014. [4] Rates for non-CRP residential customers will be 2.3% higher in 2013 than they would have been absent the DSM portfolio investment, but by 2014 their average bills will decline by 1.2%. Not shown in the 5-year rate/bill analysis are the substantial bill reductions realized after 2014. These modest near-term rate and bill impacts are acceptable considering the magnitude of the ensuing bill reductions over the remaining lifetime of the investment.

Tables 11 – 13 show the pre and post DSM effects on bills as well as rate impacts broken out by customer classes.

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4 This analysis does not include any electric rate or bill reductions from electric energy impacts.

Table 11: Pre-DSM

Pre-DSM	2010-11	2011-12	2012-13	2013-14	2014-15
Gas Revenues ($000)					
Non-CRP Residential	$ 550,858	$ 572,914	$ 581,818	$ 594,403	$ 599,317
Commercial	$ 159,159	$ 167,091	$ 171,863	$ 178,004	$ 182,059
Industrial	$ 13,645	$ 14,157	$ 14,402	$ 14,709	$ 14,839
Municipal	$ 14,450	$ 15,250	$ 15,728	$ 16,283	$ 16,624
Housing Authority - GS	$ 3,688	$ 3,855	$ 3,938	$ 4,042	$ 4,088
Housing Authority - PHA	$ 9,786	$ 10,199	$ 10,371	$ 10,597	$ 10,659
Number of Customers					
Non-CRP Residential	379,778	375,986	372,232	371,034	367,502
Commercial	25,254	25,396	26,077	24,071	24,364
Industrial	779	805	780	1,076	1,071
Municipal	924	976	941	556	565
Housing Authority - GS	1,956	1,956	1,956	1,956	1,956
Housing Authority - PHA	828	938	819	813	808
Average Monthly Bill					
Non-CRP Residential	$ 121	$ 127	$ 130	$ 134	$ 136
Commercial	$ 525	$ 548	$ 549	$ 616	$ 623
Industrial	$ 1,460	$ 1,465	$ 1,539	$ 1,140	$ 1,154
Municipal	$ 1,304	$ 1,303	$ 1,393	$ 2,442	$ 2,451
Housing Authority - GS	$ 157	$ 164	$ 168	$ 172	$ 174
Housing Authority - PHA	$ 985	$ 907	$ 1,056	$ 1,086	$ 1,100
Sales Volume (Mcf)					
Non-CRP Residential	29,280	29,170	28,957	28,801	28,662
Commercial	10,601	10,757	10,912	11,075	11,247
Industrial	991	991	992	992	993
Municipal	1,306	1,315	1,327	1,337	1,346
Housing Authority - GS	209	209	209	209	209
Housing Authority - PHA	590	587	583	579	576
Average Rate ($/therm)					
Non-CRP Residential	1.88	1.96	2.01	2.06	2.09
Commercial	1.50	1.55	1.58	1.61	1.62
Industrial	1.38	1.43	1.45	1.48	1.49
Municipal	1.11	1.16	1.19	1.22	1.23
Housing Authority - GS	1.76	1.84	1.88	1.93	1.95
Housing Authority - PHA	1.66	1.74	1.78	1.83	1.85

Table 12: Post-DSM

Post-DSM	2010-11	2011-12	2012-13	2013-14	2014-15
DSM Benefit ($000)					
Non-CRP Residential	$ (462)	$ (1,601)	$ (3,194)	$ (5,016)	$ (5,756)
Commercial	$ (33)	$ (213)	$ (548)	$ (1,001)	$ (1,187)
Industrial	$ -	$ (4)	$ (15)	$ (33)	$ (41)
Municipal	$ (3)	$ (110)	$ (272)	$ (444)	$ (513)
Housing Authority - GS	$ (1)	$ (4)	$ (9)	$ (15)	$ (17)
Housing Authority - PHA	$ (3)	$ (13)	$ (27)	$ (43)	$ (49)
DSM Spending ($000)					
Non-CRP Residential	$ 2,026	$ 3,997	$ 5,444	$ 6,285	$ 2,169
Commercial	$ 245	$ 692	$ 1,217	$ 1,514	$ 525
Industrial	$ 9	$ 28	$ 58	$ 75	$ 26
Municipal	$ 45	$ 521	$ 760	$ 786	$ 265
Housing Authority - GS	$ 3	$ 8	$ 11	$ 14	$ 5
Housing Authority - PHA	$ 9	$ 23	$ 32	$ 41	$ 15
USC Credit ($000)					
Non-CRP Residential	$ 2,674	$ 3,166	$ 2,022	$ 814	$ (3,329)
Commercial	$ 968	$ 1,167	$ 762	$ 313	$ (1,306)
Industrial	$ 90	$ 108	$ 69	$ 28	$ (115)
Municipal	$ 119	$ 143	$ 93	$ 38	$ (156)
Housing Authority - GS	$ 19	$ 23	$ 15	$ 6	$ (24)
Housing Authority - PHA	$ 54	$ 64	$ 41	$ 16	$ (67)
Gas Revenues ($000)					
Non-CRP Residential	$ 555,096	$ 578,476	$ 586,091	$ 596,486	$ 592,400
Commercial	$ 160,339	$ 168,736	$ 173,293	$ 178,831	$ 180,090
Industrial	$ 13,745	$ 14,289	$ 14,514	$ 14,779	$ 14,709
Municipal	$ 14,611	$ 15,804	$ 16,308	$ 16,662	$ 16,220
Housing Authority - GS	$ 3,709	$ 3,881	$ 3,954	$ 4,047	$ 4,052
Housing Authority - PHA	$ 9,846	$ 10,273	$ 10,416	$ 10,611	$ 10,558
Average Monthly Bill					
Non-CRP Residential	$ 122	$ 128	$ 131	$ 134	$ 134
Commercial	$ 529	$ 554	$ 554	$ 619	$ 616
Industrial	$ 1,471	$ 1,479	$ 1,551	$ 1,145	$ 1,144
Municipal	$ 1,318	$ 1,350	$ 1,444	$ 2,498	$ 2,391
Housing Authority - GS	$ 158	$ 165	$ 168	$ 172	$ 173
Housing Authority - PHA	$ 991	$ 913	$ 1,060	$ 1,087	$ 1,089
Average Bill Impact					
Non-CRP Residential	0.8%	1.0%	0.7%	0.4%	-1.2%
Commercial	0.7%	1.0%	0.8%	0.5%	-1.1%
Industrial	0.7%	0.9%	0.8%	0.5%	-0.9%
Municipal	1.1%	3.6%	3.7%	2.3%	-2.4%
Housing Authority - GS	0.6%	0.7%	0.4%	0.1%	-0.9%
Housing Authority - PHA	0.6%	0.7%	0.4%	0.1%	-0.9%

Table 13: Rate Impact

Rate Impact	2010-11	2011-12	2012-13	2013-14	2014-15
DSM Savings (Mcf)					
Non-CRP Residential	(53)	(184)	(362)	(556)	(622)
Commercial	(4)	(26)	(67)	(119)	(138)
Industrial	0	(0)	(2)	(4)	(5)
Municipal	(0)	(12)	(30)	(48)	(54)
Housing Authority - GS	(0)	(1)	(1)	(2)	(2)
Housing Authority - PHA	(0)	(2)	(3)	(5)	(6)
Average Rate ($/therm)					
Non-CRP Residential	1.90	2.00	2.05	2.11	2.11
Commercial	1.51	1.57	1.60	1.63	1.62
Industrial	1.39	1.44	1.47	1.50	1.49
Municipal	1.12	1.21	1.26	1.29	1.25
Housing Authority - GS	1.77	1.86	1.90	1.95	1.95
Housing Authority - PHA	1.67	1.76	1.80	1.85	1.85
Average Rate Impact					
Non-CRP Residential	1.0%	1.6%	2.0%	2.3%	1.0%
Commercial	0.8%	1.2%	1.5%	1.6%	0.1%
Industrial	0.7%	1.0%	1.0%	0.9%	-0.4%
Municipal	1.1%	4.6%	6.1%	6.1%	1.6%
Housing Authority - GS	0.6%	0.9%	1.0%	1.0%	0.1%
Housing Authority - PHA	0.7%	1.0%	1.0%	1.0%	0.0%

C. Job Creation

Investing in cost-effective energy-efficiency creates jobs in two ways, one direct, and the other indirect. Direct job creation results hiring related to implementing the programs created. Indirect job creation results from the substitution of local capital spent in the local economy rather than sending the capital otherwise spent for natural gas delivered from afar. Several times more jobs are created by the indirect or income effect from cost-effective energy-efficiency investment. The net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability. Customers will tend to spend most of this additional money and save the rest. This additional spending creates a "multiplier" effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion (possibly higher than 80%) of jobs created due to EE stay within the Commonwealth.[5]

The number of jobs created from investments in EE directly relates to the total resource value of the energy that these measures save Studies of employment impacts of DSM

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5 How many of theses jobs would be created within the Philadelphia metro area cannot be stated with precision. Studies show that the number is bound to be substantial. The direct labor requirements for installing the efficiency measures are almost entirely local. The efficiency technologies have significant but unknown local value added. The indirect employment effects depend on how much of the extra spending money generated by gas cost savings gets spent within the local economy. Such issues would require additional research and analysis to quantify the range of likely local job creation.

use energy savings as a surrogate for total resource value. A recent meta-study of U.S. data found that estimates for the number of jobs created range from 9 to 125 for every one trillion Btu (TBtu) saved. Most studies estimate that between 30 and 60 net jobs are created by saving one TBtu (Laitner and McKinney 2008). In New York, New Jersey, and Pennsylvania, the American Council for an Energy Efficient Economy (ACEEE) projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010 (Nadel et al 1997).

PGW estimates that its gas DSM portfolio will generate between 579 and 965[6] net additional jobs over the lifetime of the efficiency measures installed over the next five years. This range is based on assuming that each TBTU of gas savings creates between 30 and 50 full-time equivalent jobs in Pennsylvania.

D. Greenhouse Gas Reductions

Table 14 provides the estimated reduction in carbon dioxide from each of the programs over the next five years.

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6 These estimates do not include the additional jobs created from the electric savings that result from the PGW proposed programs.

Table 14

PHILADELPHIA GAS WORKS
GAS DSM PLAN
GREENHOUSE GAS EMISSION REDUCTIONS

	Emissions Reductions from Gas Savings					
Cumulative Annual CO_2 (Short Tons)	2010	2011	2012	2013	2014	Lifetime Reductions
Comprehensive Residential Heating Retrofit	-	3,011	7,528	13,551	19,574	293,608
Enhanced Low-income Retrofit	-	5,328	10,657	15,985	21,314	319,705
Premium Efficiency Gas Appliances and Heating Equipment	-	2,039	8,158	14,276	20,395	305,920
Commercial and Industrial Equipment Efficiency Upgrades	-	-	208	677	1,301	19,516
Municipal Facilities Comprehensive Efficiency Retrofit	-	-	845	1,691	2,536	38,039
High-Efficiency Construction	-	-	270	946	2,298	34,468
Commercial and Industrial Retrofit	-	-	416	1,353	2,602	39,032
Portfolio Total	-	10,379	28,083	48,479	70,019	1,050,287

	Emissions Reductions from Electricity Savings					
Cumulative Annual CO_2 (Short Tons)	2010	2011	2012	2013	2014	Lifetime Reductions
Comprehensive Residential Heating Retrofit	-	2,988	7,470	13,445	19,421	157,207
Enhanced Low-income Retrofit	-	3,127	6,255	9,382	12,510	99,589
Premium Efficiency Gas Appliances and Heating Equipment	-	-	-	-	-	-
Commercial and Industrial Equipment Efficiency Upgrades	-	-	-	-	-	-
Municipal Facilities Comprehensive Efficiency Retrofit	-	-	-	-	-	-
High-Efficiency Construction	-	-	-	-	-	-
Commercial and Industrial Retrofit	-	-	-	-	-	-
Portfolio Total	-	6,115	13,724	22,827	31,931	256,796

	Emissions Reductions from Gas and Electricity Savings					
Cumulative Annual CO_2 (Short Tons)	2010	2011	2012	2013	2014	Lifetime Reductions
Comprehensive Residential Heating Retrofit	-	5,999	14,998	26,996	38,995	450,815
Enhanced Low-income Retrofit	-	8,456	16,912	25,367	33,823	419,294
Premium Efficiency Gas Appliances and Heating Equipment	-	2,039	8,158	14,276	20,395	305,920
Commercial and Industrial Equipment Efficiency Upgrades	-	-	208	677	1,301	19,516
Municipal Facilities Comprehensive Efficiency Retrofit	-	-	845	1,691	2,536	38,039
High-Efficiency Construction	-	-	270	946	2,298	34,468
Commercial and Industrial Retrofit	-	-	416	1,353	2,602	39,032
Portfolio Total	-	16,494	41,808	71,307	101,950	1,307,083

VI. PGW GAS DSM PROGRAM DESCRIPTIONS

Following are narrative descriptions of each of the seven DSM programs PGW plans to implement over the next five years. Each program description summarizes the target market, efficiency technologies, marketing strategy, delivery and over sight, and participation and savings goals.

The first four programs have more detail due to the earlier start of program activities. The last three programs have less detail since the level of detail required for full-scale launch in 2011 would be premature. Throughout 2011, PGW will work on designing and implementing pilot versions of these programs. The latter two are particularly difficult to characterize in more detail because PGW has yet to work out how the design and implementation of these programs will be integrated and coordinated with other parties.

A. Comprehensive Residential Heating Retrofit (Home Performance with ENERGY STAR™)

A comprehensive retrofit program designed for high-use heating customers, this program utilizes the existing federal Home Performance with ENERGY STAR™ program to identify potential technologies that private contractors then use with customers.

Comprehensive Residential Heating Retrofit					
	2010	2011	2012	2013	2014
		COSTS (2009$)			
Customer Incentives	$ -	$ 1,401,356.45	$ 2,102,034.67	$ 2,802,712.89	$ 2,802,712.89
Administration and Management	$ 50,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00
Marketing and Business Development	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Contractor Costs	$ -	$ 484,388.28	$ 726,582.42	$ 968,776.56	$ 968,776.56
Inspection and Verification	$ -	$ 43,875.75	$ 52,650.90	$ 52,650.90	$ 35,100.60
On-site Technical Assessment	$ -	$ -	$ -	$ -	$ -
Evaluation	$ -	$ -	$ 75,000.00	$ -	$ 75,000.00
TOTAL:	**$ 100,000.00**	**$ 2,079,620.48**	**$ 3,031,267.99**	**$ 3,974,140.35**	**$ 3,956,590.05**
		GAS SAVINGS (BBtu)			
Annual Incremental:	-	57	85	114	114
Cumulative Annual:	-	57	142	256	369

1. Target Market

The Comprehensive Residential Heating Retrofit Program is designed to help residential customers with higher than average gas usage find ways to improve the energy efficiency of their homes. The program targets the 40% of residential customers with the highest annual energy consumption. Using recent consumption data, an eligible home will use 81 MCF per year. Currently, there are 35,107 eligible customer households. After the consumption criteria have been met, all one to four unit owner occupied residences are eligible. For non-owner occupied homes, explicit approval must be obtained from the landlord before an energy audit may be scheduled.

2. Target Measures

The program utilizes an energy audit to address low-cost maintenance issues and identify cost-effective weatherization early-replacements of furnaces and clothes washers. Incentives will be provided on a project level and not at the individual measure level. Please see the Financial Strategies section for more detail on project incentives.

The basis of the program is an energy audit, in which a "core treatment" is administered and further efficiency opportunities are identified at no cost to the customer. The core treatment consists of a walk-through where the auditor will perform basic low-cost treatments and maintenance, including but not limited to:

1. A blower-door test to quantify the amount of air leakage and determine what additional air-sealing measures would be required. These typically include door sweeps, weather stripping and caulking.

2. An examination of the home's HVAC system and the implementation of some low-cost measures such as duct sealing, radiator bleeding repairs, and the installation of radiator reflectors. For furnaces, often a "clean, test, and tune" (CTT) service, including filter replacement, will get the furnace burning efficiently and avoid the need for early replacement.

3. Measures to increase the efficiency of water heating, such as fixing hot water leaks, water heater wrapping, and installing low-flow showerheads and faucet aerators.

4. With the permission of the homeowner, the auditor will replace incandescent light-bulbs with more efficient compact fluorescent lamps (CFLs) at no cost to the customer.

After the walkthrough, the auditor will have a sit down presentation to discuss measures to be installed and their associated savings. The auditor will discuss the customer's energy usage goals, as well as potential benefits to the customer's health, comfort, safety, and quality of life. The auditor will also provide literature on savings tips and any efficiency programs for which the customer may be eligible. Measures that the auditor will test for cost-effectiveness fall into three categories: weatherization, heating system, and hot water usage.

Weatherization efforts, beyond those offered through the core treatment, are mainly focused on increasing roof and attic insulation, although all cost-effective insulation will be explored. Roof repairs will be made where needed to make insulation effective. Implementers will also install an under-porch partition where deemed appropriate. An under-porch partition is an insulated and sealed wall to partition off the section of basement areas that extend underneath the front porch of some homes.

In examining heating systems, two main measures are utilized, the first being set back thermostats. To achieve maximum savings, extensive training is provided along with the installation of the thermostats. In houses with multiple occupants, the thermostat is used to maintain a steady setting, returning to a customer-established baseline ever few hours, rather than the typical set-up/set-back strategy. The program will also target early replacement of heating systems with high-efficiency units. A high-efficiency furnace must have at an Annual Furnace Utilization Efficiency[7] (AFUE) of 85% or higher.

3. Marketing and Outreach

PGW will determine how to best divide marketing efforts and how to utilize network connections to leverage marketing. Both customers and energy service providers such as contractors and material and equipment suppliers will be covered by the plan. Table 15 describes a variety of potential marketing efforts geared towards customer enrollment along with sample market actors.

Table 15: Marketing Efforts to Drive Customer Adoption of Program

Technique	Description	Market Actors
Brochures	Program promotional materials for distribution through various marketing activities. Brochures will be provided in multiple languages.	PGW
Targeted Direct Mailings	Individual letters (separate from bills) addressed to customers with high savings potential.	PGW
Bill Inserts	Inserting program information into the bills of the customers.	PGW
Email Blasts	Standardized emails that are sent to a distribution list. This is a low cost way to reach a large audience	PGW
Website	Program information that is accessible online. In addition, application forms will be available for electronic submission.	PGW
Canvassing	Going door-to-door to get customers to enroll in the program. If customers are not home, promotional program material will be left behind.	PGW

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[7] AFUE shows the percentage of fuel energy converted into heat. A higher number indicates less energy consumption for the same amount of heat.

Technique	Description	Market Actors
Seasonal Press Releases	Coordinating awareness with seasonal heating demand.	PGW
Print/Radio Advertising	Promotional spots will include in-language advertisements to target various customer segments.	PGW
Community Events	Participation in local community events with the potential to reach eligible customers. This will usually be done in cooperation with other local/state organizations	PGW and Local/State Government
Cross-promotion	Coordination with other programs, retailers & manufacturers to promote a menu of programs	PGW, Retailers, Manufacturers, and other Organizations
Coordination with Local Agencies	Working with a variety of local agencies to make them aware of the program and to have the agencies encourage their clients to enroll. Potential organizations include those that serve seniors, single-mothers, or provide housing aid.	PGW, Community Development Corporations, and other Non-profit Organizations
Customer Contact	Training customer service representatives to notify customers of their eligibility for the program.	PGW
Telemarketing	Targeting specific customers for contact over the phone and direct solicitation for enrollment in the program.	PGW Sub-contractor

Other efforts will be pursued beyond driving customer enrollment. PGW will work to educate and raise awareness of energy efficiency efforts amongst contractors and suppliers of material and equipment. Potential actions include training sessions and general workshops on installing and servicing energy efficient measures. Through coordination and cooperation, PGW will develop and implement a comprehensive marketing strategy to reach both users and suppliers of energy efficiency services.

4. Delivery and Oversight

A customer contacts PGW. After eligibility has been established, PGW schedules an audit with the customer. The audit consists of a core treatment (described in the Target Measures section), assessment of savings potential, and a discussion of the options with the customer. After the initial audit, PGW negotiates with the customer on measure options, costs, and incentives. When a package of measures and an acceptable incentive have been agreed upon, the customer is responsible for overseeing the installation of the agreed upon measures. PGW will provide a list of certified contractors and any further assistance as needed. PGW then verifies that the installation was correct and that the customer knows how to use the new equipment before the incentive is paid. As detailed above, most of the customer interaction is handled by a subcontractor, which in turn is overseen by PGW.

PGW selects the subcontractor through a competitive bid process and then trains and works with the subcontractor to market the program, providing customer data as appropriate for determining eligibility and carrying out marketing efforts. PGW also oversees the general program budget. In its role as overseer, PGW will monitor vendor performance and overall program results, including customer satisfaction and market responsiveness. To encourage the subcontractor to seek deeper savings, an incentive will be provided if certain savings goals are exceeded. If the subcontractor fails to achieve a lower threshold of savings, they will pay a predefined penalty. PGW will independently verify savings through a number of random onsite inspections.

The subcontractor works on marketing and outreach with PGW. They provide the energy audit and oversee the installation of measures and payment of incentives. They also provide their own post-installation inspection and verification of savings. They work together with PGW on raising awareness and training contractors and coordinating with other state and local programs.

5. Financial Strategies

PGW will work with the customer to determine financing options and establish a basis for customer cash flow. Using these projections, PGW will provide an incentive that buys the project down to a two-year simple payback. All CFLs will be offered at no cost to the customer to achieve maximum savings from basic lighting opportunities.

Financing options will be offered through PGW's cooperation with other state and local programs. The most relevant, being the Keystone HELP program, which offers both secured and unsecured, below market rate loans for energy efficiency retrofits to Pennsylvania residents. PGW will work with Keystone HELP to make sure that program requirements align, and that only one energy audit will be required. PGW will also reach out to local banks and credit unions, to put together a range of offers on loans for energy efficiency retrofits.

In the following example, the customer is presented a project that will cost a total of $910. PGW in this case would offer an incentive of $267, leaving $643 for the customer to contribute toward the investment. This is two years' worth of expected bill savings which last 15 years. In conjunction with the financial incentive offer, PGW would help the customer access financing for three years through a source such as Keystone HELP. At an interest rate of 6%, the annual payments on the loan total $235. As shown in the table below, the customer puts no money down, and enjoys a net positive cash flow of $87, more than a third of the annual cost of servicing the loan.

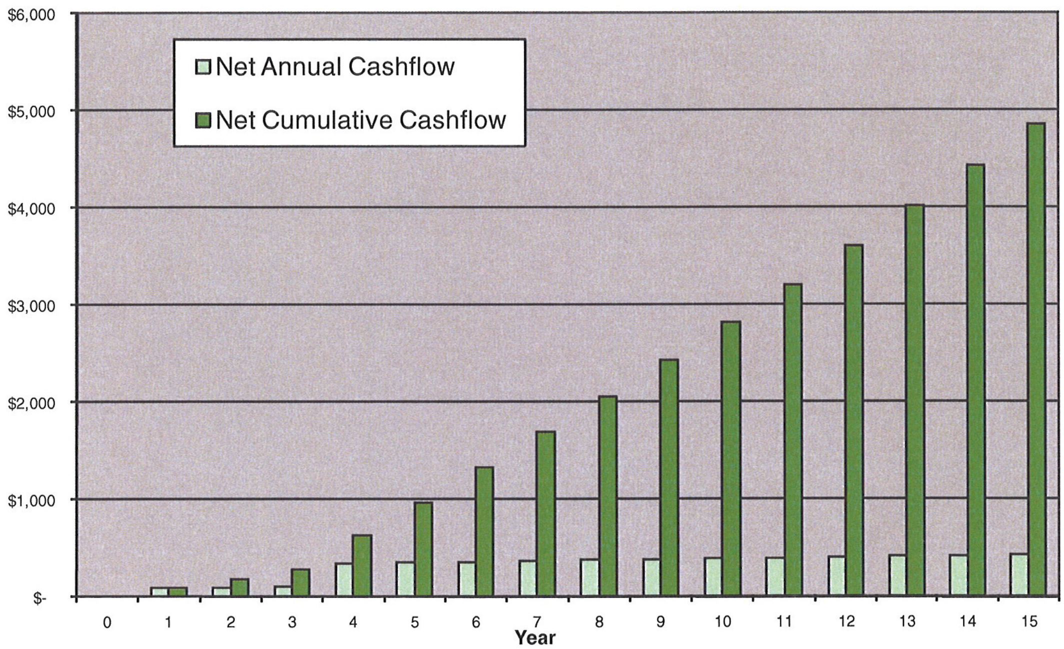
Table 16: Cash Flow from Typical Residential Retrofit Project

Year	Annual Payments (Principal & Interest)	Annual Electric Savings	Annual Natural Gas Savings/ (Costs)	Net Annual Cashflow	Net Cumulative Cashflow
0				**$ -**	**$ -**
1	$ (235)	$ 17	$ 305	**$ 87**	**$ 87**
2	$ (235)	$ 17	$ 311	**$ 93**	**$ 179**
3	$ (235)	$ 17	$ 317	**$ 100**	**$ 279**
4	0	$ 18	$ 323	**$ 341**	**$ 620**
5	0	$ 18	$ 330	**$ 348**	**$ 968**
6	0	$ 18	$ 336	**$ 355**	**$ 1,322**
7	0	$ 19	$ 343	**$ 362**	**$ 1,684**
8	0	$ 19	$ 350	**$ 369**	**$ 2,053**
9	0	$ 20	$ 357	**$ 376**	**$ 2,430**
10	0	$ 20	$ 364	**$ 384**	**$ 2,814**
11	0	$ 20	$ 371	**$ 392**	**$ 3,205**
12	0	$ 21	$ 379	**$ 399**	**$ 3,605**
13	0	$ 21	$ 386	**$ 407**	**$ 4,012**
14	0	$ 22	$ 394	**$ 416**	**$ 4,428**
15	0	$ 22	$ 402	**$ 424**	**$ 4,851**

The following figure is a graphical representation of the customer's cash flow over the lifetime of the installed measures.

Figure 6

Cash Flow



B. Enhanced Low-income Retrofit

The Enhanced Low-income Retrofit Program seeks to provide cost-effective energy savings to low-income customers who participate in PGW's Customer Responsibility Program (CRP). A secondary goal of the program is to reduce the overall long-term cost of the CRP as paid by all firm customers. In general, the program makes the customer's homes more energy efficient and comfortable by:

- Repairing or replacing older and less energy efficiency heating systems
- Providing comprehensive weatherization services
- Educating customers on ways to reduce their energy along with basic health and safety information
- Raising awareness of energy conservation and encouraging the incorporation of energy saving behavior
- Targeting high-use customers to maximize impact and increase cost-effectiveness
- Streamlining the delivery mechanism through implementation contractors

Enhanced Low-income Retrofit					
	2010	2011	2012	2013	2014
COSTS (2009$)					
Customer Incentives	$ -	$ 6,019,695.67	$ 6,019,695.67	$ 6,019,695.67	$ 6,019,695.67
Administration and Management	$ 50,000.00	$ 150,000.00	$ 150,000.00	$ 150,000.00	$ 150,000.00
Marketing and Business Development	$ -	$ -	$ -	$ -	$ -
Contractor Costs	$ -	$ 529,158.24	$ 529,158.24	$ 529,158.24	$ 529,158.24
Inspection and Verification	$ -	$ 9,586.20	$ 9,586.20	$ 9,586.20	$ 9,586.20
On-site Technical Assessment	$ -	$ -	$ -	$ -	$ -
Evaluation	$ -	$ 75,000.00	$ -	$ 75,000.00	$ -
TOTAL:	**$ 50,000.00**	**$ 6,783,440.11**	**$ 6,708,440.11**	**$ 6,783,440.11**	**$ 6,708,440.11**
GAS SAVINGS (BBtu)					
Annual Incremental:	-	101	101	101	101
Cumulative Annual:	-	101	201	302	402

1. Target Market

Any customer participating in PGW's Customer Responsibility Program (CRP) is eligible for participation in the Enhanced Low-income Retrofit Program. Started in 1990, the CRP is a low-income payment assistance program available to any residential customer with gross household income at or below 150% of the federal poverty level (FPL). Participants pay a fixed percentage of their income (between 8 and 10 percent) to maintain gas service[8]. To be considered for the Enhance Low-income Retrofit Program, customers must be 1) an owner occupied one to four residential dwelling units OR 2) renters who pay for their own natural gas heat and have a natural gas account in their name.

To effectively utilize the programs resources, PGW will specifically target customers that have been identified as heavier users of natural gas. In a previous pilot program, PGW has found that targeting high use customers produces larger savings at a lower marginal cost[9]. By targeting higher use customers PGW can increase the program cost-effectiveness and have a greater impact on reducing the cost of the CRP on ratepayers.

2. Delivery and Oversight

Customer eligibility requirements are met through participation in the CRP. PGW encourages enrollment in the program through direct mailing, telemarketing, bill inserts, public relations, and community outreach (please see the Marketing Strategies section for further detail). The low income retrofit program offers the same energy efficiency services that the Comprehensive Residential Heating Retrofit Program offers, but at no cost to the customer. This leads to a slight difference in procedure.

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8 *Universal Service and Energy Conservation Plan – 2008 to 2010*. Philadelphia Gas Works. June 1, 2007.

9 See conclusions from Blasnik, Michael. *Philadelphia Gas Works' Conservation Works Program Calendar Year 2006 and Comprehensive Treatment Pilot*. M. Blasnik & Associates: November 19, 2008.

The subcontractor performs an energy audit and identifies all cost-effective measures. With the permission of the customer, the subcontractor oversees measure installation by certified contractors. The subcontractor then verifies installation and pays the contractor. PGW will process payments to the subcontractor and undertake a number of random inspections to (1) ensure that measures have been correctly installed and savings are being achieved, (2) guarantee that program guidelines have been met, and (3) collect customer feedback.

3. Target Measures

The measures offered through the Enhanced Low Income Program are identical to the options offered through the Comprehensive Residential Heating Retrofit Program. Available measures include comprehensive weatherization efforts such as air sealing and added insulation as well as heating system replacement and low-flow showerheads and aerators for faucets. Education is particularly import within the low income program, and Energy Auditors will have a "kitchen table" discussion on energy saving tips, proper care and maintenance, health and safety information, and the benefits from the various measures.

4. Marketing and Outreach

In marketing the Enhanced Low Income Program, PGW will determine a comprehensive marketing approach. Marketing efforts will focus on specific subgroups to drive participation. High use customers will be targeted since they provide the greatest potential for savings and net benefits. Efforts will be made to reach all participants in the CRP through direct mailings, bill inserts, and email blasts. The Marketing and Outreach section of the Comprehensive Residential Heating Retrofit Program contains a comprehensive list of marketing activities.

Strategies that are specifically designed for the Enhanced Low Income Program include 1) Targeted mailings of high usage customers 2) Bill inserts for all CRP participants 3) Outreach to organizations serving the same target market 4) Door-to-door canvassing in under-utilized neighborhoods and 5) Telemarketing efforts focused on the highest usage customers. Since eligibility for the program is achieved through participation in the CRP, participants who have online account access will be able to enroll in the program directly through their online customer portal. After submitting a request, the program administrator will contact the customer to schedule an energy audit.

5. Financial Strategies

All cost-effective efficiency measures are installed at no cost to the customer. This drives higher participation levels, which in turn leads to higher net-benefits and a reduction in the overall long-term cost of the CRP for rate payers.

C. Premium Efficiency Gas Appliances and Heating Equipment

This program works to promote the selection of residential-sized efficient gas appliances and heating equipment at the time of purchase and ultimately to transform the market to shift to the high-efficiency options.

Premium Efficiency Gas Appliances and Heating Equipment					
	2010	2011	2012	2013	2014
COSTS (2009$)					
Customer Incentives	$ -	$ 472,953.66	$ 1,418,860.98	$ 1,418,860.98	$ 1,418,860.98
Administration and Management	$ 50,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00
Marketing and Business Development	$ 50,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00
Inspection and Verification	$ -	$ 11,317.60	$ 33,952.80	$ 33,952.80	$ 33,952.80
Evaluation	$ -	$ -	$ 75,000.00	$ -	$ 75,000.00
TOTAL:	**$ 100,000.00**	**$ 659,271.26**	**$ 1,702,813.78**	**$ 1,627,813.78**	**$ 1,702,813.78**
GAS SAVINGS (BBtu)					
Annual Incremental:	-	38	115	115	115
Cumulative Annual:	-	38	154	269	385

1. Target Market

This program targets residential and small commercial customers making purchases of gas appliances and heating equipment.

2. Delivery and Oversight

As the program administrator PGW will provide retailer support and broad-based marketing as well as set up the system for providing rebates to customers purchasing the high-efficiency equipment. PGW will investigate opportunities to coordinate with other programs targeting this market. The program budget provides funding for outside technical assistance contractors to assist PGW management in working with other entities and market actors.

3. Target Measures

Measures in the program include high-efficiency furnaces, high-efficiency water heaters, and high-efficiency clothes washers. The following table shows a list of efficient measures and their incentives.

Table 17

Residential Efficienct Equipment Incentives

Measure	Minimum Efficiency	Rebate
Tankless Water Heaters (w/ electronic ignition)	EF = 80	$ 150.00
Tankless Water Heaters (w/ electronic ignition)	EF = 82	$ 300.00
Storage Tank (min 40 gallons)	N/A	$ 50.00
Natural Gas Furnace	AFUE = 92	$ 200.00
Natural Gas Furnace	AFUE = 92 / ECM driving fan	$ 400.00
Natural Gas Water Boiler(w/ electronic ignition)	.82 AFUE	$ 200.00
Natural Gas Water Boiler(w/ electronic ignition)	.85 AFUE	$ 500.00
Natural Gas Water Boiler(w/ electronic ignition)	.90 AFUE	$ 1,000.00
Programmable Thermostat	N/A	$ 25.00

4. Marketing and Outreach

PGW will work with equipment manufacturers, distributors, and retailers/vendors to make the high-efficiency equipment available for purchase. Engineers and contractors will be encouraged to recommend or specify the choice of high-efficiency equipment to customers making purchases of gas appliances and heating equipment.

5. Financial Strategies

Financial incentives covering 80% of the incremental cost of premium-efficiency equipment will be offered to customers to help offset the barriers that the higher cost of the more efficient equipment often pose.

D. Commercial and Industrial Equipment Efficiency Upgrades

This program works to promote the selection of commercial and industrial efficient gas heating and process equipment at the time of new installation or scheduled replacement and ultimately to transform the market to shift to the high-efficiency options.

Commercial and industrial equipment efficiency upgrades

	2010	2011	2012	2013	2014
		COSTS (2009$)			
Customer Incentives	$ -	$ -	$ 120,415.79	$ 270,935.52	$ 361,247.36
Customer Incentives	$ -	$ 75,000.00	$ 100,000.00	$ 100,000.00	$ 100,000.00
Direct Implementation:	$ -	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Evaluation:	$ -	$ -	$ 4,324.67	$ 9,730.50	$ 12,974.00
	$ -	$ -	$ -	$ 75,000.00	$ -
TOTAL:	**$ -**	**$ 125,000.00**	**$ 274,740.45**	**$ 505,666.02**	**$ 524,221.36**
		GAS SAVINGS (BBtu)			
Annual Incremental:	-	-	4	9	12
Cumulative Annual:	-	-	4	13	25

1. Target Market

This program targets commercial and industrial customers planning on the installation or replacement of gas heating or process equipment.

2. Delivery and Oversight

As the program administrator, PGW will provide retailer support and broad-based marketing as well as set up the system for providing rebates to customers purchasing the high-efficiency equipment. PGW will investigate opportunities to coordinate with other programs targeting this market. As with the residential equipment program, PGW has budgeted funds for engaging outside technical assistance contractors to help work with other entities and market actors.

3. Target Measures

Measures in the program include high-efficiency furnaces, space heating boilers, water heaters, process boilers, pool heaters, cooking equipment and commercial clothes washers.

The following table shows a list of measures along with their incentives

Table 18

Commercial & Industrial Equipment and Efficiency Measure Incentives

Measure	Minimum Efficiency	Rebate	Limits
Programmable Thermostat	N/A	$ 25.00	Limit 5
Boiler Reset Control (1 Stage)	N/A	$ 150.00	Limit 2
Boiler Reset Control (2 Stage)	N/A	$ 250.00	Limit 2
Roof Insulation	R-19	20% of installed cost	Maximum $10,000
Roof Insulation	R-30	20% of installed cost	Maximum $10,000
Wall Insulation	BCR greater than 1.0 using TRC	20% of installed cost	Maximum $10,000
Floor Insulation	BCR greater than 1.0 using TRC	20% of installed cost	Maximum $10,000
Pipe Insulation	BCR greater than 1.0 using TRC	$1.50/linear foot	Limit 500 linear feet
Duct Insulation	BCR greater than 1.0 using TRC	$1.50/linear foot	Limit 500 linear feet
Windows	BCR greater than 1.0 using TRC	$1.00/sq foot	Limit 2,500 sq feet
Natural Gas Furnace	AFUE = 90	$ 500.00	N/A
Natural Gas Furnace	AFUE = 92	$ 500.00	N/A
Natural Gas Furnace	AFUE = 92 / ECM driving fan	$ 700.00	N/A
Natural Gas Furnace	AFUE = 94 / ECM driving fan	$ 900.00	N/A
Natural Gas Furnace	AFUE = 95 / ECM driving fan	$ 900.00	N/A
Natural Gas Water Boiler(w/ electronic ignition)	AFUE = 85	$ 800.00	N/A
Natural Gas Water Boiler(w/ electronic ignition)	AFUE = 90	$ 1,200.00	N/A
Natarual Gas Steam Boiler	AFUE = 82	$ 800.00	N/A
Indirect Water Heater	N/A	$ 300.00	N/A

4. Marketing and Outreach

PGW will work with equipment manufacturers, distributors, and retailers/vendors to make the high-efficiency equipment available for purchase. Engineers and contractors will be encouraged to recommend or specify the choice of high-efficiency equipment to customers installing gas heating and process equipment.

5. Financial Strategies

Financial incentives covering 80% of the incremental cost of premium-efficiency equipment will be offered to customers to help offset the barriers that the higher cost of the more efficient equipment often poses.

E. Municipal Facilities Comprehensive Efficiency Retrofit

PGW plans a comprehensive retrofit program designed for municipal facilities. This program utilizes energy-service contractors to identify and install cost-effective energy-saving technologies.

Municipal Facilities Comprehensive Efficiency Retrofit					
	2010	2011	2012	2013	2014
COSTS (2009$)					
Administration and Management	$ -	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Inspection and Verification	$ -	$ -	$ 1,539.00	$ 1,539.00	$ 1,539.00
On-site Technical Assessment	$ -	$ -	$ 615,600.00	$ 615,600.00	$ 615,600.00
TOTAL:	**$ -**	**$ 50,000.00**	**$ 667,139.00**	**$ 667,139.00**	**$ 667,139.00**
GAS SAVINGS (BBtu)					
Annual Incremental:	-	-	16	16	16
Cumulative Annual:	-	-	16	32	48

1. Target Market

This program targets facilities owned and/or operated by the City of Philadelphia. These include a wide range of buildings, including schools, office buildings, and public housing.

2. Delivery and Oversight

PGW will select energy-service contractors through competitive bid and provide random inspections to verify that work was done and savings are being achieved. PGW will also provide assistance with engineering and economic assessment of retrofit efficiency options and coordination with participation in other programs. PGW will investigate opportunities to coordinate with other programs targeting this market. In particular, PGW will help the City undertake the technical and economic assessments required to qualify for financial incentives offered by PECO's nonresidential electric DSM program.

3. Target Measures

Potential measures in the program include high-efficiency furnaces, space heating boilers, water heaters, HVAC controls and shell improvements. PGW will also actively seek to identify and quantify the costs and performance of electric efficiency measures qualifying for financial incentives under PECO's DSM program. These will include lighting, HVAC, and motors and drives.

4. Marketing and Outreach

Facility managers, department heads, and financial officers will be asked to allow private energy-service contractors to conduct audits of their facilities and identify cost-effective energy-saving retrofit opportunities.

5. Financial Strategies

Financing advice will be offered for cost-effective gas-saving measures. In particular, PGW will assist the City with analysis of efficiency investment financial performance in the order to qualify for federal funding or to access either traditional or nontraditional financing facilities.

F. High-efficiency Construction

A comprehensive program designed for new construction, remodeling, and renovation efficiency improvements for residential and commercial buildings. This program seeks to transform the market so that energy-efficient design and construction becomes standard practice.

High-efficiency Construction	2010	2011	2012	2013	2014
COSTS (2009$)					
Customer Incentives	$ -	$ -	$ 208,502.83	$ 521,257.09	$ 1,042,514.17
Administration and Management	$ -	$ 75,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00
Marketing and Business Development	$ -	$ 50,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Inspection and Verification	$ -	$ -	$ 8,497.56	$ 21,243.89	$ 42,487.78
Evaluation	$ -	$ -	$ -	$ -	$ 75,000.00
TOTAL:	**$ -**	**$ 125,000.00**	**$ 342,000.39**	**$ 667,500.98**	**$ 1,210,001.95**
GAS SAVINGS (BBtu)					
Annual Incremental:	-	-	5	13	26
Cumulative Annual:	-	-	5	18	43

1. Target Market

This program targets residential and commercial customers engaged in new construction, remodeling, and renovation of their buildings.

2. Delivery and Oversight

PGW will provide support for and financial assistance to those involved with new construction, remodeling, and renovation projects. PGW will also provide assistance with engineering and economic assessment of the proposed efficiency options. PGW will investigate opportunities to coordinate with other programs targeting this market.

3. Target Measures

Potential measures in the program include high-efficiency furnaces, space heating boilers, water heaters, HVAC controls, insulation and window upgrades.

4. Market Actors and Technologies

This program seeks to affect the energy-efficiency decisions by the parties involved with new construction, remodeling, and renovation, such as property developers, property managers, home or building owners, real estate agents, architects, engineers, builders, and contractors.

5. Financial Strategies

Financial incentives covering 80% of the incremental cost of high-efficiency equipment will be offered to customers to help offset the barriers that the higher cost of the more efficient equipment often pose. This also includes the costs for comprehensive design assistance from architects and engineers.

G. Commercial and Industrial Retrofit

A comprehensive retrofit program designed for commercial and industrial facilities, this program promotes the installation of a wide array of cost-effective energy-saving technologies.

Commercial and Industrial Retrofit					
	2010	2011	2012	2013	2014
COSTS (2009$)					
Customer Incentives	$ -	$ -	$ 107,036.26	$ 240,831.58	$ 321,108.77
Administration and Management	$ -	$ 50,000.00	$ 75,000.00	$ 75,000.00	$ 75,000.00
Marketing and Business Development	$ -	$ 25,000.00	$ 50,000.00	$ 50,000.00	$ 50,000.00
Inspection and Verification	$ -	$ -	$ 4,324.67	$ 9,730.50	$ 12,974.00
Evaluation	$ -	$ -	$ -	$ 75,000.00	$ -
TOTAL:	**$ -**	**$ 75,000.00**	**$ 236,360.92**	**$ 375,562.08**	**$ 459,082.77**
GAS SAVINGS (BBtu)					
Annual Incremental:	-	-	8	18	24
Cumulative Annual:	-	-	8	26	49

1. Target Market

This program targets commercial and industrial facilities.

2. Delivery and Oversight

PGW will provide support and financial assistance for customers engaged in comprehensive audits and retrofits of their facilities. PGW will provide random inspections to verify that work was done and savings are being achieved. PGW will also provide assistance with engineering and economic assessment of retrofit efficiency options. PGW will investigate opportunities to coordinate with other programs targeting this market.

3. Target Measures

Potential measures in the program include high-efficiency furnaces, space heating boilers, water heaters, HVAC and process controls, shell improvements, pool heaters, cooking equipment, process boilers, and process optimization.

4. Market Actors and Technologies

This program will seek to convince Facility managers, department heads, and financial officers to conduct audits of their facilities and identify cost-effective energy-saving retrofit opportunities.

5. Financial Strategies

Customized incentives will be offered based on payback buydown and customer cash flow, including electric and other resource savings.

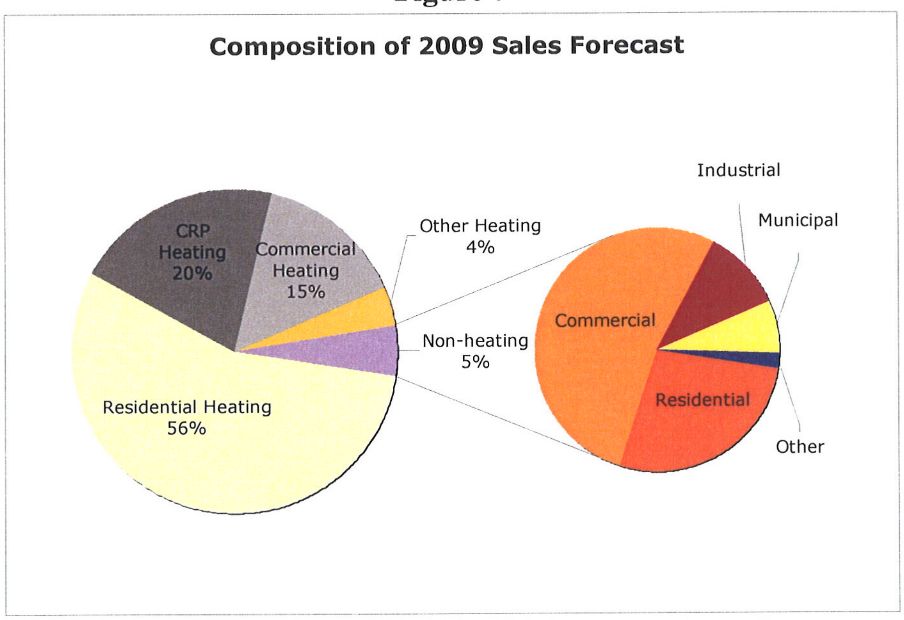
VII. ASSUMPTIONS AND CALCULATIONS

This section provides additional information on the assumptions and calculations PGW used to estimate energy, economic, and environmental impacts. A working electronic version of the cost-effectiveness calculator used to prepare these results is available.

A. Customers and Sales

PGW estimated the number of eligible customers in each market addressed by its DSM portfolios. Figure 7 summarizes the contributions of various customer groups to total gas energy requirements.

Figure 7



The PGW DSM programs are all directed at firm heating customers. Table 19 provides the sales and customer forecast for various heating customers in 2009.

Table 19
PHILADELPHIA GAS WORKS

	Forecast Budget 2009				
	Number of Customer Billings for February		Gas Sales		Gas Sales per Customer
Non-heating					
Residential	35,107		699,037		20
CRP	1,115		47,419		43
Commercial	5,158		1,339,896		260
Industrial	211		278,908		1,322
Municipal	106		177,030		1,670
NGV Firm	1		327		327
Total Firm Non-heating	**41,698**		**2,542,617**		61
Heating					
Residential	351,006	77.5%	28,409,135	58.5%	81
CRP	79,885	17.6%	10,472,516	21.6%	131
Housing Authority - GS	2,047	0.5%	222,184	0.5%	109
Commercial	18,582	4.1%	7,703,575	15.9%	415
Industrial	499	0.1%	477,416	1.0%	957
Municipal	380	0.1%	656,349	1.4%	1,727
Housing Authority - PHA	804	0.2%	636,815	1.3%	792
Total Firm Heating	**453,203**	100.0%	**48,577,990**	100.0%	107
Total Firm	**494,901**		**51,120,607**		**103**
Heating share of total firm	92%		95%		
Source	SR 12		SR11		

B. Program Inputs

PGW estimated program costs and savings based on a variety of sources. The two residential retrofit programs comprise the large majority of spending and savings. These estimates are grounded in PGW's experience with its low-income program. Based on evaluated results, PGW projected per-customer savings and costs assuming continued improvement in past performance, especially as the program is targeted to high-use customers in both the low-income and non-low income programs.

Savings projections for other programs are less robust compared to the residential retrofit programs. Costs and savings assumptions for efficiency measures in other markets are based on experience and plans of other utilities. PGW's estimated administration costs are based on judgment. The detailed work plans PGW plans to file prior to initiating any of its plans will contain updated estimates for these elements.

Table 20 presents detailed assumptions on customer acceptance rates and program costs and savings inputs.

Table 20

PHILADELPHIA GAS WORKS
Five Year Gas Demand-Side Management Plan
PROGRAM INPUTS

	5 years						Staging % of Maximum Customer Participation in Year								Per-customer Financial Incentive	
PROGRAM	Total Eligible Customers	Annual Pace	Annual Customers Eligible	Applicability/ Feasibility	Acceptance Rate	Maximum Annual Customer Participation	2010	2011	2012	2013	2014	Per-Customer Gas Savings	Per-Customer Gas Usage (MCF)	Installed or Incremental Cost per MCF/yr	%	$/MCF/yr
Comprehensive Residential Heating Retrofit	351,006	5%	17,550	80%	50%	7,020		50%	75%	100%	100%	20%	81	$ 56.22	33%	$ 18.74
Enhanced Low-income Retrofit	79,885	7%	5,326	90%	80%	3,834		100%	100%	100%	100%	20%	131	$ 56.22	100%	$ 56.22
Premium Efficiency Gas Appliances and Heating Equipment	452,704	5%	22,635	90%	67%	13,581		33%	100%	100%	100%	8%	106	$ 12.29	100%	$ 12.29
Commercial and industrial equipment efficiency upgrades	19,461	5%	973	80%	67%	519			33%	75%	100%	5%	454	$ 40.88	75%	$ 30.66
Municipal Facilities Comprehensive Efficiency Retrofit	380	20%	76	90%	90%	62			100%	100%	100%	15%	1,727	$ 40.88	0%	$ -
High-efficiency Construction	22,660	1%	4,532	50%	75%	1,700			20%	50%	100%	20%	75	$ 40.88	100%	$ 40.88
Commercial and Industrial Retrofit	19,461	7%	1,297	60%	67%	519			33%	75%	100%	10%	454	$ 40.88	33%	$ 13.63

C. Measure Inputs

Table 21 provides additional information used to characterize the efficiency measures analyzed.

Table 21

MEASURE INPUTS (Program Year 1, 2010)
24-Nov-09 14:16

Portfolio					Natural Gas Savings		Energy	Electricity Savings					Operation and Maintenance Costs		Utility Customer Incentives	
					Usage			Capacity					Baseline Equipment Components/Maintenance			
									Coincidence Factors							
Measure Name	Program ID (e.g., A or B)	Measure Life (years)		Incremental Installed Cost or Full Cost for Retrofit (2009$)	1 = NG Base 2 = NG Space Heat 3 = NG DHW 4 = NG User Defined 5 = NG User Defined	Natural Gas Saved (MMBtu/yr)	Annual kWh Saved	Maximum Load Reduction (kW)	Summer GenerationCapacity (% of Maximum)	Winter Gener. Capacity (% of Maximum)	Transm. Capacity (% of Maximum)	Distribution Capacity (% of Maximum)	Component 1 Life (years)	Component 1 Replacement Cost (2009$)	Electric Utility Customer Incentive (2009$)	Gas Utility Customer Incentive (2009$)
[0]	[1]	[2]		[4]	[5]	[6]	[7]	[12]	[13]	[14]	[15]	[16]	[29]	[30]	[37]	[38]
Comprehensive Residential Heating Retrofit	A	15		$910	2	16.19	167	0.278	70%	0%	70%	70%				$303
CFL direct install	A	6.5		$9.59			63	0.054	8%	30%	8%	8%	0.86	$0.50		$9.59
Enhanced Low-income Retrofit	B	15		$1,474	2	26.22	134	0.223	70%	0%	70%	70%				$1,474
CFL direct install	B	6.48		$9.59			63	0.054	8%	30%	8%	8%	0.86	$0.50		$9.59
Premium Efficiency Gas Appliances and Heating Equipme	C	15		$104	3	8.50										$104
Commercial and Industrial Equipment Efficiency Upgrades	D	15		$928	3	22.71										$696
Municipal Facilities Comprehensive Efficiency Retrofit	E	15		$10,591	2	259.09										$0
High-Efficiency Construction	F	15		$613	2	15.01										$613
Commercial and Industrial Retrofit	G	15		$1,856	3	45.41										$619

D. Penetration

Table 22 indicates the annual number of measures installed in each program in each year. Note that the CFL direct install numbers refers to the number of CFL lamps.

Table 22

Program Year	1	2	3	4	5
Year	2010	2011	2012	2013	2014
In Program Penetration					
Comprehensive Residential Heating Retrofit	0	3,510	5,265	7,020	7,020
CFL direct install	0	35,101	52,651	70,201	70,201
Enhanced Low -income Retrofit	0	3,834	3,834	3,834	3,834
CFL direct install	0	38,345	38,345	38,345	38,345
Premium Efficiency Gas Appliances and Heating Equip	0	4,527	13,581	13,581	13,581
Commercial and Industrial Equipment Efficiency Upgra	0	0	173	389	519
Municipal Facilities Comprehensive Efficiency Retrofit	0	0	62	62	62
High-Efficiency Construction	0	0	340	850	1,700
Commercial and Industrial Retrofit	0	0	173	389	519

E. Energy Savings

Table 23 provides a year-by-year breakdown of electricity and gas savings by program.

Table 23

Year:	Total	2010	2011	2012	2013	2014
Portfolio						
Incremental annual MWh Saved (Net at meter)		0	5,730	7,130	8,530	8,530
Incremental annual MWh Saved (In prog, at meter)		0	5,730	7,130	8,530	8,530
Cumulative annual MWh Saved (Net, at meter)		0	5,730	12,860	21,390	29,920
Cumulative annual MWh Saved (Net, at gen.)		0	6,647	14,918	24,812	34,707
Incremental annual Summer kW Saved (Net at meter)		0	1,598	2,016	2,433	2,433
Incremental annual Summer kW Saved (In prog, at meter)		0	1,598	2,016	2,433	2,433
Cumulative annual Summer kW Saved (Net, at meter)		0	1,598	3,614	6,048	8,481
Cumulative annual Summer kW Saved (Net, at gen.)		0	1,854	4,192	7,015	9,838
Incremental annual BBtu Gas Saved (Net)		0	196	334	385	406
Incremental annual BBtu Saved (In prog)		0	196	334	385	406
Cumulative annual BBtu Saved (Net)		0	196	530	915	1,321
Lifetime BBtu Saved (Net)	19,817	0	2,938	5,011	5,772	6,096
Comprehensive Residential Heating Retrofit Program To						
Incremental annual MWh Saved (Net at meter)		0	2800	4200	5599	5599
Incremental annual MWh Saved (In prog, at meter)		0	2800	4200	5599	5599
Cumulative annual MWh Saved (Net, at meter)		0	2800	6999	12599	18198
Cumulative annual MWh Saved (Net, at gen.)		0	3248	8119	14614	21110
Incremental annual Summer kW Saved (Net at meter)		0	835	1253	1670	1670
Incremental annual Summer kW Saved (In prog, at meter)		0	835	1253	1670	1670
Cumulative annual Summer kW Saved (Net, at meter)		0	835	2088	3758	5429
Cumulative annual Summer kW Saved (Net, at gen.)		0	969	2422	4360	6297
Incremental annual BBtu Gas Saved (Net)		0	57	85	114	114
Incremental annual BBtu Saved (In prog)		0	57	85	114	114
Cumulative annual BBtu Saved (Net)		0	57	142	256	369
Lifetime BBtu Saved (Net)	5,540	0	852	1278	1705	1705
Enhanced Low-income Retrofit Program Total						
Incremental annual MWh Saved (Net at meter)		0	2930	2930	2930	2930
Incremental annual MWh Saved (In prog, at meter)		0	2930	2930	2930	2930
Cumulative annual MWh Saved (Net, at meter)		0	2930	5861	8791	11722
Cumulative annual MWh Saved (Net, at gen.)		0	3399	6799	10198	13597
Incremental annual Summer kW Saved (Net at meter)		0	763	763	763	763
Incremental annual Summer kW Saved (In prog, at meter)		0	763	763	763	763
Cumulative annual Summer kW Saved (Net, at meter)		0	763	1526	2289	3052
Cumulative annual Summer kW Saved (Net, at gen.)		0	885	1770	2655	3541
Incremental annual BBtu Gas Saved (Net)		0	101	101	101	101
Incremental annual BBtu Saved (In prog)		0	101	101	101	101
Cumulative annual BBtu Saved (Net)		0	101	201	302	402
Lifetime BBtu Saved (Net)	6,032	0	1508	1508	1508	1508
Premium Efficiency Gas Appliances and Heating Equipm						
Incremental annual BBtu Gas Saved (Net)		0	38	115	115	115
Incremental annual BBtu Saved (In prog)		0	38	115	115	115
Cumulative annual BBtu Saved (Net)		0	38	154	269	385
Lifetime BBtu Saved (Net)	5,772	0	577	1732	1732	1732
Commercial and Industrial Equipment Efficiency Upgrad						
Incremental annual BBtu Saved (In prog)		0	0	4	9	12
Cumulative annual BBtu Saved (Net)		0	0	4	13	25
Lifetime BBtu Saved (Net)	368	0	0	59	133	177
Municipal Facilities Comprehensive Efficiency Retrofit Pr						
Incremental annual BBtu Gas Saved (Net)		0	0	16	16	16
Incremental annual BBtu Saved (In prog)		0	0	16	16	16
Cumulative annual BBtu Saved (Net)		0	0	16	32	48
Lifetime BBtu Saved (Net)	718	0	0	239	239	239
High-Efficiency Construction Program Total						
Incremental annual BBtu Gas Saved (Net)		0	0	5	13	26
Incremental annual BBtu Saved (In prog)		0	0	5	13	26
Cumulative annual BBtu Saved (Net)		0	0	5	18	43
Lifetime BBtu Saved (Net)	650	0	0	77	191	383
Commercial and Industrial Retrofit Program Total						
Incremental annual BBtu Gas Saved (Net)		0	0	8	18	24
Incremental annual BBtu Saved (In prog)		0	0	8	18	24
Cumulative annual BBtu Saved (Net)		0	0	8	26	49
Lifetime BBtu Saved (Net)	736	0	0	118	265	353

F. Avoided Costs

The economic evaluation of an energy-efficiency measure requires an estimate of the measure's benefits. The major benefit of gas energy-efficiency programs is the reduction of gas use and associated costs to customers. Those avoided costs may be passed on to customers by the utility, third-party suppliers, or both, but they are all eventually paid by customers.

Electric avoided costs are often computed for a number of cost drivers, such as summer and winter contribution to system peak load, and seasonal energy use for on- and off-peak periods. In the cost-benefit computation, analysts estimate the effect of a proposed measure or program on each of the cost drivers. The benefit of the energy-efficiency proposal is then estimated by multiplying the energy savings for each cost driver by the per-unit avoided cost for that driver, and adding up the benefits for all the drivers. This approach works well for evaluation of electric energy-efficiency programs, simplifying the costs of serving loads for 8,760 hours to a few cost drivers, which can be estimated for the wide variety of electric end uses (*e.g.*, residential and commercial space heating, space cooling, ventilation, water heating, refrigeration, indoor and outdoor lighting, clothes drying, cooking, computers and other plug loads, as well as a range of industrial loads).

Like most detailed analyses of avoided gas costs, this study's calculation of avoided costs is structured differently than that usually used to estimate electric avoided costs. Planning and procurement for natural gas is primarily concerned with daily loads, rather than annual loads, so there are fewer load shapes. There are also fewer end uses for gas than electricity, since very little gas is used for lighting, refrigeration, or residential air conditioning, and no gas is used for computers or ventilation. Hence, it is feasible to compute avoided costs for the load shapes of the few gas end uses. In the cost-benefit analysis, the benefit of each energy-efficiency measure can be estimated as the measure's annual savings times a single load-specific avoided cost.

This load-shape approach to defining avoided costs allows for distinctions between the costs of different end uses that impose different costs, even for similar seasonal usage levels. An end use that does not vary with weather, such as cooking or clothes drying, may use the same amount of gas in the winter as a heating boiler, but the gas to serve the boiler will be more expensive. The boiler will predictably use more gas on very cold days, when gas is most expensive, and less on mild days, when gas is relatively cheap. Serving the boiler requires the reservation of enough pipeline capacity to meet load on typical cold days, and the construction of local transmission-and-distribution capacity and supplemental gas supplied to meet load on extraordinarily cold days. The boiler will use more gas on cold days, when regional gas demand is high and prices are high. The development of avoided cost by load shape allows for the reflection of these differences between loads even within a season or a month.

This estimate of avoided gas costs comprises the following three parts:

- Commodity: The market prices of gas delivered to a utility's citygate in a normal year
- Peaking capacity: The costs of local capacity to cover the difference between normal and design-peak conditions
- Local transmission and distribution (T&D): The utility's cost of building, operating and maintaining the high-pressure transmission and lower-pressure distribution system in its service area

1. Commodity Cost

We forecast the monthly delivered gas price to the PGW citygate for gas delivered evenly over the month, as the sum of

- The NYMEX forward price for gas delivered to Henry hub for September 2009 through August 2020, plus
- The NYMEX forwards for the price basis from Henry Hub to Transco Zone 6, which includes the PGW citygate, through December 2012. After 2012, we escalate the basis at the same rate as the Henry Hub forward price.[10]

Beyond 2020, we escalate the delivered gas price at an assumed inflation rate of 2%. From these forwards, we computed annual commodity costs for the following three load shapes:

- Baseload, including industrial processes, cooking, and clothes drying, modeled as using the same amount of gas every day.
- Space heating, modeled as using gas each day in proportion to daily heating degree days (HDD).
- Water heating, modeled as a mix of baseload and space-heating load. This approximation reflects the observation that gas usage by water-heating customers rises in the winter months, probably as a combination of higher standby losses and warmer water temperatures for baths, showers and washing.

While gas utilities do not purchase a large portion of their supply in the daily spot market, the short-term market in which utilities can procure gas to meet higher-than-expected load, or sell off gas when their supplies exceed their needs determines the value of the gas. Every dekatherm of gas that a PGW consumer does not use is one more dekatherm that is available to someone in the spot market who is willing to pay the spot price for that gas. Depending on the gas-supply situation and contracts of the utility (or gas supplier), the utility may avoid buying gas from the spot market, or sell more gas into the spot market, or reduce its use of some longer-term contract.

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[10] Forward prices are the closing values for April 14, 2009.

In the longer term, annual and multi-year contracts should average near the spot prices for the same time periods. Estimating the effect of specific load reductions on the supply portfolio and costs of any particular utility or gas supplier is complicated, since the calculation would have to model purchases, sales and usage of a variety of gas supplies, pipeline capacity, storage resources, and supplementary resources. This approach would also require non-public data from competitive gas suppliers. The spot-market price is a reasonable estimate of the resource benefit from reduced commodity use.

2. Baseload Commodity

For baseload end uses, where use of gas does not vary with weather or the season, the analysis weights the forecast monthly gas price by the number of days in the month.

3. Space-Heating Commodity

The cost of commodity for space heating varies from the cost of baseload in two ways. First, the amount of gas used varies among months, and is concentrated in the higher-cost winter months. Second, within each month, space heating uses more gas on the colder days, when gas tends to be more expensive than the average for the month.
For the first factor, the monthly percentage the study assumed that the monthly use of gas for space heating is proportional to the monthly sum of daily heating degree days (HDDs). Heating degree days are the difference between the days' average temperature and a base temperature, at which space-heating use is assumed to be zero. That base temperature, or balance point, is lower than the temperature maintained by the thermostat, since the building is warmed by sun shining in the windows and by interior gains (waste heat) from lights, appliances, equipment, and people.

We used the monthly average HDDs with a base of 65° F for 1978–2007 published by NOAA.[11]

The second factor, the effect of the intra-month correlation of price and load, reflects the fact that heating loads use more gas on colder days within each month, and that prices tend to be higher on cold days.[12] This correction was computed as the typical ratio of the heating-load-weighted market price to the average daily price for the month. Since the NYMEX prices are for gas delivered evenly over the month, multiplying that ratio by the NYMEX-based price forecast results in an estimate of the price of gas for heating load in the month.

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11 "2007 Local Climatological Data: Annual Summary With Comparative Data, Philadelphia, Pennsylvania (KPHL)," National Oceanographic and Atmospheric Administration, ISSN 0198-4535.

12 The utility or a gas supplier can meet load in those high-load high-priced days with spot purchases, by reserving storage and associated transportation to the citygate, or by reserving additional pipeline capacity directly to the citygate. All these approaches impose costs that would not be needed for a load that was constant across the days of the month.

Of course, gas prices vary due to factors other than the current day's temperature in Philadelphia, including the following:

- Wind and sunshine on that day, since heating load will be higher on a cloudy, windy 40°F day than a sunny calm day with the same air temperature.
- Weather in other parts of North America. A cold snap in California will drive up wellhead prices in Texas and Alberta, and hence prices for deliveries to Pennsylvania. Cold temperatures in New England or New York not only raise wellhead prices, but also market prices for delivery to New York citygates. Conversely, mild weather elsewhere can moderate prices in Philadelphia, even when it is cold in Philadelphia.
- Weather on other days. High gas demand in earlier days of the same month, or in earlier months, will tend to deplete storage and push prices higher. Forecasts of cold weather in coming days and weeks will tend to push up price before the cold front hits, as users scramble to put gas into storage.
- Gas in storage, which depends on the weather, other gas demands over the previous year or so, market participants' guesses regarding price tends, and other factors.
- Demand for gas for electric generation, which varies during the month with oil prices and outages of coal and nuclear plants and between years as load grows and supplies change.
- Gas production capacity, which changes within winter months primarily due to freeze-ups of gas wells in producing areas, but changes significantly between years due to depletion and new additions (and sometimes hurricanes).

For this study, the intra-month price ratio was computed for each calendar month using data for each of the last two gas years, 2006/07 and 2007/08. The analysis computes the ratio of load-weighted to average monthly price for each month.

Equation 1: Intra-Month Heating Price Ratio.

$$\text{intra-month heating price ratio} = \frac{\left[\dfrac{\sum_{month} HD_{day} \times P_{day}}{\sum_{month} HD_{day}}\right]}{\left[\dfrac{\sum_{month} P_{day}}{\text{\# days in the month}}\right]}$$

where HD_{day} = heating degree-days for the day
P_{day} = delivered price for the day

The ratios tend to be highest in the winter and close to 1.00 in the shoulder months.

The heating commodity cost for each year is the sum across months of the following product:

NYMEX monthly forward × monthly HDD % × intra-month price ratio

The annual heating commodity cost is significantly greater than the annual baseload commodity cost. The annual residential heating avoided cost, averaged over the period 2006–2025, is 12% greater than average annual baseload price. These differences can largely be explained by the fact that most of the heating usage is in the high-priced months of January, February, and December.

4. Water-Heating Commodity

Based on previous experience, the analysis assumed that water-heating load is similar in shape to 75% baseload and 25% space-heating load. The heating-like shape is probably attributable to a combination of higher standby losses and longer, hotter showers and baths in cold weather.

5. Commodity-Cost Summary

The attached spreadsheet shows avoided commodity costs for the three load shapes. The relationships among the prices for the various load shapes are as expected. The heating cost is higher than the water-heating cost, which is higher than the baseload cost. The average costs of utility gas supplies, which serve large amounts of heating load, tend to be much higher than the flat year-round gas supplies reflected in the baseload commodity costs. The average avoided commodity cost will similarly be more expensive than the avoided commodity cost for a flat year-round gas supply.

6. Peaking Capacity Cost

In addition to buying and delivering the gas required in a normal year, a gas utility must be prepared to meet much higher loads on an extremely cold (design-peak) day.[13] The prices for gas in a normal year do not include the costs of reserving capacity and supplies to meet design-day conditions. Those design loads are normally met by local storage (liquefied natural gas) and/or peaking off-system storage and associated transportation. Based on an estimated cost of capacity of $100/yr/Dth-day for NYSERDA's Seneca storage project, and $90/yr/Dth-day for propane capacity ("Natural Gas Energy Efficiency Resource Development Potential in New York," Mosenthal, et al, NYSERDA, October 31, 2006), we used a value of $100/ yr/Dth-day.

Since baseload has no increment of sendout on the design peak over average conditions, it would not have any peaking capacity charges.

While actual gas-system supply planning is quite complex, the problem was simplified by assuming that peaking capacity is required for the difference between sendout on a design peak day and on the average of the peak day in the two years. PGW's design day is 65

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[13] Energy supplies must also be sufficient to meet colder-than-normal weather for days or weeks at a time.

degree days, which was actually experienced on January 17, 1982. The maximum HDDs were 50 in 2007/08 and 48 in 2006/07, for an average of 49 HDD in the two years from which our commodity-cost shapes were adjusted.

7. Avoided T&D Cost

As peak loads grow, local distribution companies need to expand their internal transmission and distribution systems by adding parallel mains, looping, and increasing operating pressures, and increasing the size of new and replacement lines. The expenditures vary across each utility's service area and over time. Typically relatively small increments of load require expensive upgrades, while other load areas have excess capacity for many years resulting in no expansion costs.

Marginal or avoided T&D costs are therefore generally estimated by comparing growth-related costs to peak load growth over a period of several years. Based on estimates from upstate New York utilities, discounted 50% to reflect the expected decline in PGW total load, we used an avoided T&D cost of $50/Dth-day.

G. Program Cost-effectiveness Analysis

The analysis used a discount rate of 5.9%. This is the same discount rate used in present worth calculations in PGW's most recent evaluation of its low-income retrofit program.

The following tables present more detailed information on annual program benefits and costs by year. Table 24 shows each program's incremental contribution to lifetime benefits and costs by year; Table 25 provides the running total of cumulative net benefits by program by year.

Table 24

NPV of Incremental Lifetime Costs and Benefits (2009$)					
Program Year:	1	2	3	4	5
Year:	**2010**	**2011**	**2012**	**2013**	**2014**
Total Resource Test					
Portfolio Total					
Benefits	0	18,904,520	29,075,847	32,416,368	32,760,826
Costs	350,000	10,961,350	14,903,502	16,688,091	16,706,493
Net Benefits	(350,000)	7,943,170	14,172,345	15,728,277	16,054,332
BCR	0.00	1.72	1.95	1.94	1.96
Comprehensive Residential Heating Retrofit Program					
Benefits	0	6,216,920	8,934,524	11,466,386	11,061,274
Costs	100,000	3,740,796	5,342,018	6,632,811	6,385,896
Net Benefits	(100,000)	2,476,123	3,592,506	4,833,575	4,675,378
BCR	0.00	1.66	1.67	1.73	1.73
Enhanced Low-income Retrofit Program					
Benefits	0	9,834,581	9,420,193	9,058,734	8,730,759
Costs	50,000	6,037,530	5,668,619	5,466,089	5,129,025
Net Benefits	(50,000)	3,797,052	3,751,573	3,592,646	3,601,734
BCR	0.00	1.63	1.66	1.66	1.70
Premium Efficiency Gas Appliances and Heating Equipment Program					
Benefits	0	2,853,019	8,201,463	7,879,345	7,585,836
Costs	100,000	608,024	1,478,567	1,336,991	1,349,125
Net Benefits	(100,000)	2,244,995	6,722,895	6,542,354	6,236,711
BCR	0.00	4.69	5.55	5.89	5.62
Commercial and Industrial Equipment Efficiency Upgrades Program					
Benefits	0	0	279,042	603,185	774,287
Costs	0	125,000	289,504	521,933	524,570
Net Benefits	0	(125,000)	(10,462)	81,251	249,718
BCR	n/a	0.00	0.96	1.16	1.48
Municipal Facilities Comprehensive Efficiency Retrofit Program					
Benefits	0	0	1,274,840	1,223,856	1,177,397
Costs	0	50,000	1,216,063	1,185,471	1,156,584
Net Benefits	0	(50,000)	58,777	38,384	20,812
BCR	n/a	0.00	1.05	1.03	1.02
High-Efficiency Construction Program					
Benefits	0	0	407,703	978,493	1,882,698
Costs	0	125,000	309,047	560,659	1,025,128
Net Benefits	0	(125,000)	98,655	417,834	857,570
BCR	n/a	0.00	1.32	1.75	1.84
Commercial and Industrial Retrofit Program					
Benefits	0	0	558,083	1,206,369	1,548,575
Costs	0	75,000	399,683	784,136	861,166
Net Benefits	0	(75,000)	158,400	422,233	687,409
BCR	n/a	0.00	1.40	1.54	1.80

Table 25

NPV of Cumulative Costs and Benefits					
(2009$)					
Program Year:	1	2	3	4	5
Year:	2010	2011	2012	2013	2014
Total Resource Test					
Portfolio Total					
Benefits	0	18,904,520	47,980,367	80,396,735	113,157,561
Costs	350,000	11,188,558	25,738,691	41,857,503	57,808,244
Net Benefits	(350,000)	7,715,962	22,241,676	38,539,233	55,349,317
BCR	0.00	1.69	1.86	1.92	1.96
Comprehensive Residential Heating Retrofit Program					
Benefits	0	6,216,920	15,151,444	26,617,829	37,679,103
Costs	100,000	3,802,996	9,036,200	15,483,871	21,617,885
Net Benefits	(100,000)	2,413,923	6,115,243	11,133,958	16,061,218
BCR	0.00	1.63	1.68	1.72	1.74
Enhanced Low-income Retrofit Program					
Benefits	0	9,834,581	19,254,774	28,313,509	37,044,268
Costs	50,000	6,044,966	11,638,956	16,984,338	21,972,192
Net Benefits	(50,000)	3,789,615	7,615,818	11,329,171	15,072,076
BCR	0.00	1.63	1.65	1.67	1.69
Premium Efficiency Gas Appliances and Heating Equipment Program					
Benefits	0	2,853,019	11,054,482	18,933,828	26,519,663
Costs	100,000	697,641	2,145,441	3,449,407	4,740,331
Net Benefits	(100,000)	2,155,379	8,909,042	15,484,420	21,779,332
BCR	0.00	4.09	5.15	5.49	5.59
Commercial and Industrial Equipment Efficiency Upgrades Program					
Benefits	0	0	279,042	882,226	1,656,514
Costs	0	118,034	390,816	875,651	1,366,816
Net Benefits	0	(118,034)	(111,774)	6,575	289,698
BCR	n/a	0.00	0.71	1.01	1.21
Municipal Facilities Comprehensive Efficiency Retrofit Program					
Benefits	0	0	1,274,840	2,498,696	3,676,093
Costs	0	47,213	1,190,989	2,271,021	3,290,862
Net Benefits	0	(47,213)	83,852	227,675	385,230
BCR	n/a	0.00	1.07	1.10	1.12
High-Efficiency Construction Program					
Benefits	0	0	407,703	1,386,196	3,268,894
Costs	0	118,034	412,616	950,162	1,925,587
Net Benefits	0	(118,034)	(4,913)	436,034	1,343,307
BCR	n/a	0.00	0.99	1.46	1.70
Commercial and Industrial Retrofit Program					
Benefits	0	0	558,083	1,764,452	3,313,027
Costs	0	70,820	456,490	1,207,479	2,040,365
Net Benefits	0	(70,820)	101,593	556,973	1,272,662
BCR	n/a	0.00	1.22	1.46	1.62

H. Job Creation

Table 26 presents the range of employment-impact projects for the proposed PGW programs, using a range of jobs created per trillion BTU saved.[14]

Table 26

	JOB CREATION IMPACTS OF GAS EFFICIENCY PORTFOLIO		
	30 Jobs/TBtu	**40 Jobs/TBtu**	**50 Jobs/TBtu**
RESIDENTIAL PROGRAMS			
2009	0	0	0
2010	88	118	147
2011	136	181	226
2012	148	198	247
2013	148	198	247
TOTAL	**520**	**694**	**867**
NON-RESIDENTIAL PROGRAMS			
2009	0	0	0
2010	0	0	0
2011	15	20	25
2012	25	33	41
2013	35	46	58
TOTAL	**74**	**99**	**124**
TOTAL PORTFOLIO			
2009	0	0	0
2010	88	118	147
2011	150	200	251
2012	173	231	289
2013	183	244	305
TOTAL	**595**	**793**	**991**

These values were derived based on an extensive review of research on job creation resulting from efficiency and renewable investment. That research is summarized below. Table 21 provides the list of studies reviewed.

What happens to the labor market and job creation when spending on energy efficiency (EE) increases? There are certainly jobs gained in implementing and administering the energy efficiency field. But there are also jobs that would have been created on the energy supply side that never came into existence due to energy efficiency. More importantly, the money that customers save on their energy bill has to go somewhere. To start, we will examine the dynamics of energy efficiency's effects on job creation. Then

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14 This does not include the additional jobs created from the electric savings resulting from PGW's programs.

we will look at some of the estimates that previous studies have provided for net jobs created due to energy efficiency.

The net effect of jobs lost in the energy supply sector and gained in the energy efficiency sector directly due to EE are slightly positive. National Grid's experience in Rhode Island from 1990 to 2005 found that "the jobs gained by increased spending on efficiency are offset by the jobs lost owing to lower spending on supply" (Goodman 2006). While this is good, it does not show the true benefits that come from EE.

The big gains in job creation come from the induced effects of re-spending savings on energy bills. Some studies estimate that the effects account for more than 90% of net job creation (Geller et. al. 1992). An examination of California's energy efficiency drive from 1976 to 2006 found that for every new job foregone in oil, gas, and electric power, 50 new jobs were created in California (Roland-Host 2008).

When customers save money on their energy bills, that money goes somewhere else. Most of it is re-spent in other areas of the economy, with the largest absolute rises in construction, retail trade, and the services industry (Geller et. al. 1992). The stimulation of aggregate demand from re-spending in turn increases aggregate output, a macro-economic "multiplier" effect.

In Michigan, Laitner and Kushler find a large difference in the labor-intensity of sectors with large job gains versus sectors where jobs are lost. They calculate that retail trade creates 19.1 jobs per million dollars of spending, while natural gas distribution creates 2.9 jobs (2007). Since energy supply chains are not that labor intensive, the shift of spending in these sectors to other sectors of the economy increases the multiplier effect on job creation:

> When consumers shift one dollar of demand from electricity to groceries, for example, one dollar is removed from a relatively simple, capital intensive supply chain dominated by electric power generation and carbon fuel delivery. When the dollar goes to groceries, it animates much more job intensive expenditure chains including retailers, wholesalers, food processors, transport, and farming. Moreover, a larger proportion of these supply chains (and particularly services that are the dominant part of expenditure) resides within the state, capturing more job creation from Californians for California. Moreover, the state reduced its energy import dependence, while directing a greater percent of its consumption to in-state economic activities. (Roland-Host 2008).

As Roland-Host points out, large chunk of the re-spending finds its way towards industries that require extensive local infrastructure and jobs, such as construction and retail. Because of this, leakage of labor from the area where EE originates is low. On a state level, Laitner and Kushler estimate that 80% of jobs created due to EE stay in Michigan, and they admit that this number could probably be higher (2007). Not only does EE contribute to a larger and more diverse economy and labor market, most of the benefits are localized.

There have been numerous studies over the past 30 years that examine the impacts of energy efficiency on job creation. If we focus on studies that look within the U.S., we find wide variances in time horizon, efficiency potential, and net job creation. Table 27 summarizes the findings of 48 such studies. Every state and region is unique, but we can develop a framework for comparing studies based on two key statistics.

Table 27: Summary of Past Energy Efficiency Studies

Key Indicator	Low	High	Average
Period of Analysis (Years)	5	26	12
Efficiency Potential (Savings over Reference Case)	6%	33%	23%
Benefit-Cost Ratio of Policy Scenario	1.1	4.8	1.95
Net Jobs Gained per TBtu of Efficiency Gains	9	95	49
Net Impact on GDP (as Percent Change in Ref. Case)	-0.01%	0.60%	0.15%

Source: ACEEE - *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. June 2008.

The number of net jobs gained per trillion BTus (TBtu) of efficiency gains gives us a basic rule of thumb for calculating how many jobs a given portfolio of EE programs might create. But how do we know that the portfolio of programs is comparable to these in past studies? The benefit-cost ratio gives an indication, which is independent of the size of spending, for comparing similar portfolios.

The following figure shows each study's net jobs/TBtu against their benefit-cost ratio. Most of the studies fall in the range 20 to 60 jobs/TBtu and a benefit-cost Ratio of 1.5 to 2.5. This cluster of estimates gives a good jumping off point for figuring out an appropriate number of jobs/TBtu to use.

Figure 7

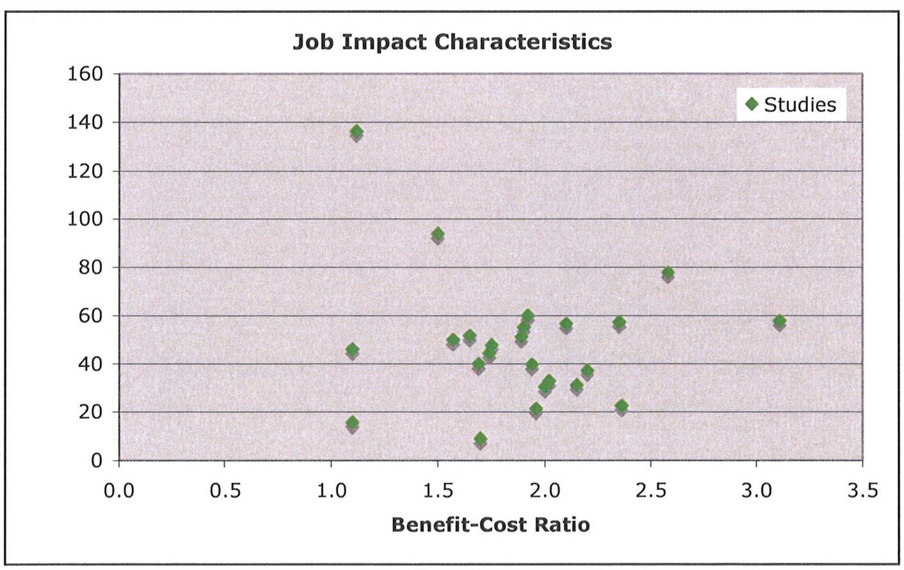

Table 28 gives a detailed breakdown of the findings from 25 studies. The most relevant numbers for Philadelphia come from the 1997 study of the Mid-Atlantic (which includes New York, New Jersey, and Pennsylvania). This study estimated approximately 57 net jobs/TBtu with a portfolio that has a benefit-cost ratio of 2.36, putting it solidly within the cluster of studies previously identified. Putting it another way, "the rise in employment, driven largely by the spending of energy bill savings, is equivalent to the number of jobs supported by the expansion or relocation of 1,095 small manufacturing plants in Mid-Atlantic region" (Nadel et al 1997).

Table 28: Summary Impacts by Region and Year of Analysis

Region	Year	Energy Saved (TBtu)	Benefit-Cost Ratio	Net Jobs	Net Jobs/TBtu
Florida	2007	1,567	1.70	14,264	9
Texas	2007	1,031	2.20	38,291	37
Midwest	1995	4,300	1.75	205,200	48
Michigan	2007	335	2.36	7,506	22
MidAtlantic	1997	2,868	2.35	164,320	57
Texas	1998	976	1.10	45,000	46
Arizona	1997	185	1.92	11,076	60
Colorado	2007	80	1.89	4,100	51
Maryland	1996	278	1.90	15,300	55
Missouri	1995	2	1.57	100	50
Mississippi	2000	49	1.50	4,600	94
Nevada	1997	131	2.02	4,300	33
U.S.	2005	13,737	1.10	215,308	16
Washington	1994	365	1.65	18,800	52
U.S.	2001	37,600	1.96	800,000	21
Wyoming	1997	87	2.15	2,700	31
Colorado	1996	212	1.94	8,400	40
Alabama	1994	266	1.69	10,590	40
Western States	1997	1,303	1.74	57,651	44
Maine	2008	68	2.00	2,070	30
Minnesota	1993	49	2.58	3,810	78
Southwestern States	2002	1,010	3.11	58,400	58
Southeastern States	1996	6,600	1.12	900,000	136
Connecticut	2004	11	2.10	622	57
Study Totals		73,109	1.72	2,592,408	35

Source: ACEEE - *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. June 2008.

Energy efficiency's impact on job creation stems mostly from the benefits of decreased energy bills. A customer who would have spent money on energy, instead divert that capital to a diverse range of economic sectors. Most of the sectors that benefit form this re-spending are much more job-intensive than the energy supply sector. Furthermore, the multiplying effect from stimulating aggregate demand adds even more jobs to the economy. For Pennsylvania, reasonable assumptions of 59 jobs per TBTu of efficiency gains have been estimated. The benefits are clear in California, where energy efficiency "reduced its (California's) energy import dependence and directed a greater percentage of its consumption to instate, employment-intensive goods and services, whose supply chains also largely reside within the state ... and facilitate(ed) the economy's transition to a low carbon future" (Roland-Host 2008).

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VIII. TECHNICAL APPENDIX

A functioning, self-documented MS Excel workbook containing the cost-effectiveness analysis and the rate and bill analysis is available upon request for easy review.

TAB

11

PGW St. No. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

TESTIMONY OF

PAUL CHERNICK
Resource Insight, Inc.

ON BEHALF OF
PHILADELPHIA GAS WORKS

DOCKET NO. R-2009-2139884

DECEMBER 2009

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and three Canadian provinces, and two Federal agencies.

Q: Have you testified previously before the Pennsylvania Public Utilities Commission (the PUC)?

A: Yes. I testified in the following dockets:

- Pennsylvania PUC R-842651, a Pennsylvania Power and Light rate case, on the need for, and operating costs and rate effects of, the Susquehanna 2 nuclear plant, on behalf of the Pennsylvania Consumer Advocate.
- Pennsylvania PUC R-850152, a Philadelphia Electric Rate Case, on rate effects of Limerick 1, on behalf of the Utility Users Committee and University of Pennsylvania.
- Pennsylvania PUC R-850290, on auxiliary rates for Philadelphia Electric, on behalf of the University of Pennsylvania and Amtrak.
- Pennsylvania PUC I-900005, R-901880, on electric-utility DSM and DSM-cost recovery, for the Pennsylvania Energy Office.
- Pennsylvania PUC Docket No. 00061346, on real-time pricing for Duquesne Lighting, on behalf of PennFuture.
- Pennsylvania PUC Docket No. R-00061366, et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric, on real-time and time-dependent pricing, on behalf of PennFuture.

Q: Please summarize your experience in the development of avoided costs.

A: I have developed or modified estimates of electric avoided costs for numerous electric utilities; many of these estimates are listed in my resume. I estimated statewide avoided costs for Vermont in 1997, and regional avoided generation costs for all of New England for a consortium of utilities in 1999, 2001, 2007, and 2009.[1] I also described the process of deriving avoided costs in a report to the Pennsylvania Energy Office in 1993.[2] I developed gas avoided costs for Boston Gas (now part of KeySpan) in the late 1980s and early 1990s, for Washington Gas Light in the 1990s, in the New England consortium reports (above) in 1999 and 2001, in two 2006 reports for NYSERDA ("Natural Gas Energy Efficiency Resource Development Potential in Con Edison Service Area" and "Natural Gas Energy Efficiency Resource Development Potential in New York"), in New York's energy-efficiency rulemaking, and for Peoples Gas Company.

Q: Please summarize your experience in the planning and promotion of energy-efficiency programs.

A: I have testified on demand-side-management potential, economics and program design in approximately 54 proceedings since 1980. In the 1990s I participated in several collaborative efforts among utilities, consumer advocates, and other parties, including those for PEPCo, BG&E, Delmarva Power, Potomac Edison,

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1 These are, respectively, "Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (1999), "Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (2001), "Avoided Energy Supply Costs in New England: 2007 Final Report" (2007), and "Avoided Energy Supply Costs in New England: 2009 Final Report" (2009), all for the Avoided-Energy-Supply-Component Study Group, c/o National Grid Company (Northborough, Massachusetts).

2 That work was in "Qualifying the Benefits of Demand Management," the fifth volume of the five-volume *From Here to Efficiency: Securing Demand-Management Resources* published in 1992 and 1993 by the Pennsylvania Energy Office.

Washington Gas Light, Central Vermont Public Service, Vermont Gas, and NYSEG. More recently, I have participated in collaboratives related to Con Edison's gas- and electricity-efficiency programs and New York statewide program rules and objectives.

Q: Please summarize your experience regarding recovery of utility energy-efficiency program costs and associated revenue losses.

A: I first proposed a combined revenue-stabilization and conservation-funding mechanism in testimony on alternatives to the Seabrook nuclear power plant before the New Hampshire Public Utilities Commission in Docket No. DE1-312 in October 1982. My qualifications list a number of subsequent engagements related to ratemaking for energy efficiency, including recovery of direct costs and lost revenue.

I have supported broader revenue stabilization than proposed by the utilities in some cases (e.g., in Ontario), and proposed modifications to utility decoupling proposals in other situations (e.g., for Con Edison's electric sales, Vectren's Indiana gas territories). I have also worked on issues of cost recovery in collaborative efforts among utilities, consumer advocates, and other parties, including Con Edison's continuing gas revenue-per-customer decoupling collaborative.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Philadelphia Gas Works (PGW).

Q: What is the purpose of your testimony?

A: I describe the derivation of PGW's avoided gas costs and support PGW's proposal for the recovery of program expenditures and lost revenues resulting from the conservation program proposed in the testimony of PGW Witness John Plunkett.

Q: Please summarize the remainder of your testimony.

A: Section III describes my derivation of avoided costs for gas and electricity.

Section IV describes the need for and operation of the Efficiency Cost Recovery Adjustment, by which PGW would recover its costs related to encouraging energy efficiency and maintain its financial stability.

Section V describes my derivation of the rate impacts of DSM spending.

III. Development of Avoided Costs

A. Avoided Gas Costs

Q: Did you develop the avoided gas costs used in the economic screening of PGW's proposed energy-efficiency and conservation programs?

A: Yes.

Q: Please describe your approach.

A: The purpose of avoided costs is to estimate the benefit to consumers of reduced energy usage. The major benefit is the reduction of the quantity of gas required to serve customer loads and of the associated pipeline and storage capacity required to deliver the gas to the PGW citygate at the times customers require it. This benefit does not necessarily equal the rate paid by the customer to the utility or a natural-gas supplier in a particular month. The market price of gas varies daily or even hourly, while the gas charges may average out costs over a range of load shapes and a number of months. For customers using gas supplied by PGW, all the costs of gas used by customers will flow through to customers and all the costs saved from energy efficiency will similarly flow through to customers. Customers served by natural-gas suppliers may pay a contract rate in the short term, but those rates are likely to be adjusted over time to reflect the costs of serving the customer's actual load.

I outline my approach in this testimony. Exhibit PLC-2 presents the derivation of avoided costs in greater detail.

Q: How did you project the cost of gas or the benefit of reduced gas consumption?

A: I began with the monthly forward prices for gas at Henry Hub and added the monthly forward price for delivery of gas from Henry Hub to the PGW citygate. These are the prices in the market for equal amounts of gas delivered in each day of the month. For baseload efficiency measures, which save the same amount of energy every day, the avoided commodity cost is simply the average of the delivered gas prices across months, weighted by the number of days in the month.

For measures that save energy in proportion to heating loads, the computation is somewhat more complicated. Heating loads tend to be highest in the high-priced months, and in the highest-price days within the month. Indeed, the total heating requirement for customers in the Northeast and across the continent is the most important factor in driving price differences within a month. I assumed that the savings from heating measures would be distributed across months in proportion to normal monthly heating degree days. Within each month with significant heating load, I estimated the historical ratio of prices weighted by normal heating degree days to the simple average of the prices; see Exhibit PLC-2. The intra-month correlation of heating load and gas price results in the value of avoided heating load exceeding the value of avoided baseload by roughly 1–5% in various heating months. The avoided commodity cost for space-heating load is thus more than the cost for baseload measures. This is due to both the greater gas usage of heating in the higher-priced months and due to the greater gas usage of heating in the higher-priced days within each month.

Q: Does PGW actually purchase and sell gas in the spot market?

A: Yes. I understand that those transactions are relatively small, compared to PGW's total sales, and primarily for balancing purposes. Spot transactions set the short-run marginal cost of additional usage. Most of PGW's gas supply comes from longer-term contracts for commodity, pipeline capacity, and storage.

Q: Could PGW's avoided costs be estimated from the costs of those contracts?

A: Yes, in principle. I developed my earliest estimates of gas avoided costs, for Boston Gas in the 1980s, by estimating the effect of load reductions on specific purchases of capacity and commodity. In those days, before the competitive gas market had developed fully, contract prices were essentially the only measure of avoidable costs. Estimation of the avoided costs required Boston Gas to redispatch its entire system—pipeline purchases, storage injections and withdrawals, LNG liquefaction and withdrawals, propane injection—on a daily basis for different levels of heating load, reflecting the contracts that would be reduced with lower demand levels. This is a complicated process, and the utilities I have worked with since then (the New England and New York utilities and now PGW) have not chosen to pursue that modeling approach.

Q: Why have you used the market-valuation approach to estimating market prices, rather than the utility-specific supply approach?

A: Both practical and theoretical considerations inform this choice. Practically, the utility-supply approach is difficult to implement. Modeling the effects of load reductions on dispatch over time is quite complicated. Such an analysis would start with estimation of base-case gas dispatch, including exactly how much of each supply will be (1) used to meet daily load, (2) injected into storage or liquefied, (3) withdrawn or vaporized, or (4) sold off-system at various points from production to the PGW citygate. A reduction in load with a particular shape (such as heating load, proportional to heating degree days) would change the amount of daily gas that PGW and third-party suppliers would purchase at the production areas, and the amount that would be transported, injected into storage, liquefied, withdrawn, vaporized, sold off-system, and so on. Both the change in the dispatch and the cost reductions would depend on how PGW and other suppliers adjust their commodity, pipeline-capacity, and storage-capacity entitlements at various locations, from production to the PGW citygate in the short and long term, including renegotiation, resale, release, or allowing contracts to expire.[3]

Fortunately, with the emergence of public markets for gas delivered at particular locations, this complexity is not necessary. Theoretically, PGW's long-term avoided cost should be very close to the market price of supply. The avoidable costs of production-area commodity contracts—which may be avoided by some combination of reselling the gas, negotiating early termination or reduction of contracts, and not signing new contracts—would likely be very similar to the forward costs of gas at Henry Hub. If the market prices of supply are significantly greater than those in PGW's contracts, PGW should be retaining the contracts and selling gas into the higher-priced market, so that improved energy efficiency avoids the market price. If the market prices of supply are

3 Many of the specific products that PGW might resell or renegotiate are not widely traded, further complicating the analysis.

significantly less than those of PGW's contracts, PGW should be allowing those contracts to expire and purchasing more supply through the markets; again, the benefit of reduced load is a reduction in market purchases.

Q: How did you project avoided costs beyond the period for which you have forward prices?

A: I had monthly forwards from NYMEX for the price differential from Henry Hub to the Philadelphia citygate for 2009 through 2012. Thereafter, I escalated the differential in proportion to the escalation in the Henry Hub price through 2020, the end of NYMEX forwards for Henry Hub. After 2020, I assumed that the avoided costs would be constant in real terms. I assumed that future inflation would be 2%.

Q: Other than commodity delivered to the citygate, does energy efficiency allow PGW to avoid any other costs?

A: Yes. In addition to providing gas to meet normal weather, PGW must provide enough reserve capacity to meet loads under design conditions, including both a design day with 65 heating degree days and a design winter with heating loads approximately 19.4% greater than normal. I estimated the cost of that reserve as the price of PGW's contracts supporting its most expensive storage supply (Equitrans) times the percentage increase in heating load between normal and design winters. I took the fixed cost of the Equitrans supply as \$2.40/Dth, from Schedule SDS-8 of PGW's gas-cost-rate supporting documentation filed on June 2008. Exhibit PLC-3 shows my computation of normal heating sendout (42.5 million Dth) and the design-winter sendout increment (8.3 million Dth). As shown in Exhibit PLC-2, 0.194 Dth of peaking supply at \$2.40/Dth of peaking results in a peaking-reserve cost for heating load of about \$0.50/Dth. Baseload does not increase under design conditions, and so has no peaking-reserve cost.

Q: Please summarize your estimates of avoided gas costs.

A: Table 1 provides that summary. It is important to note that these avoided costs do not include any costs related to the carbon caps in the legislation that has passed the House of Representatives (Waxman-Markey) and has been introduced in the Senate (Boxer-Kerry). Those carbon caps could significantly increase the value of energy efficiency and conservation, since future utility DSM programs are likely to be counted as offsets and allocated credits and since both bills would require gas utilities to hold allowances starting in 2016.

Table 1: Summary of Avoided Gas Costs (2008 Dollars per MMBtu)

Year	Baseload	Space heating	Water heating
2010	$7.20	$8.57	$7.54
2011	$7.31	$8.67	$7.65
2012	$7.27	$8.58	$7.60
2013	$7.24	$8.54	$7.57
2014	$7.27	$8.57	$7.60
2015	$7.35	$8.66	$7.68
2016	$7.48	$8.81	$7.81
2017	$7.68	$9.03	$8.02
2018	$7.94	$9.32	$8.29
2019	$8.08	$9.47	$8.43
2020	$8.07	$9.46	$8.42
2021	$8.10	$9.50	$8.45
2022	$8.20	$9.61	$8.55
2023	$8.48	$9.92	$8.84
2024	$8.81	$10.29	$9.18
2025	$9.11	$10.62	$9.49
2026	$9.41	$10.95	$9.80
2027	$9.67	$11.24	$10.06
2028	$9.86	$11.45	$10.26
2029	$10.03	$11.63	$10.43
2030	$10.08	$11.70	$10.48
2031	$10.28	$11.92	$10.69
2032	$10.28	$11.92	$10.69
2033	$10.28	$11.92	$10.69

Q: Do energy-efficiency and conservation investment have other benefits, beyond those you have quantified?

A: Yes. PGW's energy-efficiency programs and resulting reductions in gas load would perform the following beneficial functions:

- create local jobs for local businesses in implementing the programs, from distributing equipment and materials to installation and inspections.
- reduce wholesale-market gas prices, particularly in the Northeast. While this is a small price effect per Ccf, it has that effect over large amounts of retail sales and the large amounts of electric energy that is priced at the marginal costs of gas-fired generators.
- provide a model for energy-efficiency programs for other Pennsylvania gas utilities, which would directly benefit the customers of those utilities and multiply the market-price benefits to consumers.
- improve customer comfort.
- potentially improve PGW cash flow, reducing the need for reliance on borrowing.
- improve customer ability to pay.
- leave customers with additional cash to be spent in Philadelphia, stimulating the local economy.

Furthermore, while most of PGW's system is experiencing falling loads and hence needs no capacity-related upgrades, there are areas in which PGW does require increased delivery capacity due to local growth, mostly to accommodate new interruptible loads. The distribution capacity freed up by energy efficiency may allow PGW to avoid some system upgrades, depending on the location and magnitude of the energy-efficiency and conservation investment and of the added loads.

Philadelphia Gas Works has not quantified these effects, but they are all properly included in the benefits of an energy-efficiency and conservation program.

B. Avoided Electric Costs

Q: Why are avoided electric costs relevant to the evaluation of PGW's energy-efficiency programs?

A: Gas energy-efficiency measures can increase or decrease electricity use. For example, some high-efficiency boilers use more electricity than standard-efficiency boilers. Tradeoffs between gas and electric savings arise in choosing between window designs that admit solar energy in the winter and those that keep out sunshine in the summer. On the other hand, building shell measures (wall and roof insulation, tighter windows), setback thermostats, and duct sealing in gas-heated buildings are likely to decrease electric use both for circulating heat (with pumps and/or fans) and for summer cooling. Accurately evaluating the cost-effectiveness of the gas energy-efficiency and conservation programs requires valuation of the changes in electricity use, along with all other costs and benefits.

In addition, while PGW (or any efficiency provider) is in the customer's premises, there may be opportunity for installing efficiency and conservation measures for other service providers, in this case the electric and water utilities. The incremental cost of having PGW install compact fluorescents when they are on site (e.g., to insulate, perform air sealing, or wrap water heaters and pipes) is much less than the cost of sending contractors to separately perform the same task for the electric company's customers.

Philadelphia Gas Works intends to attempt to work out cooperative arrangements with all energy suppliers and DSM contractors to reduce redundancy in site visits and coordinate support and incentives for construction and custom retrofits.

Q: How did you estimate electric avoided costs?

A: My computation of avoided energy costs started with NYMEX monthly forward prices for PJM on- and off-peak energy through 2013. To these flat monthly prices at the PJM Western Hub, I added adjustments for load shape, congestion (both from the PJM "2007 State of the Market Report," Market Monitoring Unit, March 11, 2008), and marginal losses. I then weighted the market energy costs across months, to derive an average annual avoided energy cost for each gas year. Beyond 2014, I assumed that the avoided energy costs would rise at the rate forecast by the Energy Information Administration (2009).

I did not explicitly recognize any effects of carbon caps or changing fuel mix in the future.

To the energy costs, I added capacity costs at the market-clearing price applicable to electric service. Since PJM obtains capacity on a locational basis, the capacity price may be essentially uniform across the entire PJM RTO, or may vary between regions. The capacity price applicable to the Philadelphia region was the Eastern MAAC zone for 2008/09 and 2009/10, the PJM RTO as a whole for 2010/11 and 2011/12, and Eastern MAAC again in 2012/13. I assumed that the capacity price in 2013/2014 would be the average of the previous auction prices ($71/kW-year, including reserve margin) in nominal dollars, without inflating the earlier prices. After 2013/14, I escalated the capacity price at inflation.

The results of my computations are summarized below in Table 2.

Table 2: Summary of Estimate of Avoided Electric Costs

	Nominal Dollars			
Gas Year	*Energy* ($/MWh)	*Capacity* ($/kW-yr)	*Total at 65% CF* ($/MWh)	**Real Dollars** (2008$/MWh)
2010/11	$65	$74	$78	$74
2011/12	$69	$55	$78	$73
2012/13	$69	$62	$80	$73
2013/14	$72	$71	$84	$75
2014/15	$75	$73	$88	$77
2015/16	$79	$74	$92	$79
2016/17	$84	$76	$97	$82
2017/18	$89	$77	$103	$85
2018/19	$96	$79	$109	$89
2019/20	$102	$80	$116	$92
2020/21	$105	$82	$119	$93
2021/22	$106	$84	$120	$92
2022/23	$110	$85	$125	$94
2023/24	$116	$87	$131	$96
2024/25	$125	$89	$141	$101
2025/26	$134	$90	$150	$106
2026/27	$143	$92	$159	$110
2027/28	$153	$94	$169	$115
2028/29	$162	$96	$179	$119
2029/30	$170	$98	$187	$122

These are very simple electric-avoided-cost placeholders. As electric companies implement energy-efficiency programs, and to the extent those efforts are coordinated with PGW's programs, the electric utilities will likely also develop more-sophisticated electric avoided costs, differentiated by season and time of use and reflecting avoided T&D costs. My simplified estimate of avoided electric costs probably understates avoided costs for most electric efficiency measures.

IV. Efficiency-Cost-Recovery Mechanism

Q: Please describe the proposed Efficiency-Cost-Recovery Mechanism.

A: The Efficiency-Cost-Recovery Mechanism (ECRM) would operate much like the existing Universal Service and Energy Conservation Surcharge. The rate would be revised each quarter, at the beginning of September, December, March, and June, and PGW would file supporting documentation for its revised rate. PGW would respond to any questions that the Commission Staff or other parties may have regarding the filings, through written responses and/or technical meetings. Each quarterly adjustment to the ECRM would be a constant dollars-per-Ccf increment for the subsequent twelve months.

On approximately March 1 of each year, PGW would make a formal reconciliation filing to be rolled into the September 1 adjustment, subject to Commission approval.

Q: What costs would the ECRM recover?

A: The ECRM would include recovery of PGW's program expenditures and revenues lost due to PGW's efficiency and conservation programs.

Q: Would the ECRM fully recover PGW's costs?

A: No. PGW does not propose to include any interest credit between the time money is spent and the time collection starts, or for the delay in recovery over twelve months. These carrying costs would be offset by reductions in cash working capital required for gas purchases. The relative magnitude of the increases and decreases in carrying costs will depend on the duration between rate cases, the amount of energy saved per dollar invested, the fraction of conservation that is heating-related, weather, and other factors. PGW does not seek to recover revenue lost as a result of response to advertising and other media messages promoting conservation nor revenue lost as a result of market changes resulting from the PGW program and its cooperative efforts with other utilities and government entities. While related to PGW efforts, these revenue losses are simply too difficult to measure.

A. Program Expenditures

Q: How would the structure of the ECRM differ from the Universal Service and Energy Conservation Surcharge?

A: The ECRM would vary by class. The Universal Service and Energy Conservation Surcharge (USC) would continue to recover the costs of energy-efficiency and conservation services to low-income residential customers, i.e. the Conservation Works Program, from all other firm classes. The costs related to customers other than low-income residential customers would be tracked separately for the following three firm classes served by the energy-efficiency programs:

- residential and public housing customers on Rate GS and on Rate PHA,
- commercial and municipal customers on Rate GS and on Rate MS,
- industrial customers on Rate GS.

Q: How does PGW propose to fund its energy-efficiency and conservation programs?

A: The programs would be funded through the following two sources:

- In many programs, the participants will pay part of the initial cost of the measures that serve them, either to PGW or to a third party implementing the measures.
- The residual direct program costs would be recovered from ratepayers, through the ECRM.

B. Lost Revenues

Q: Other than the costs of operating the programs, how do energy-efficiency and conservation programs affect PGW's earnings and liquidity?

A: The principal purpose of energy-efficiency programs is to reduce customer costs by reducing the usage of commodity. Since PGW flows through the costs of commodity to customers, reduced commodity use has little effect on PGW's financial condition, other than indirectly through the effect on cash working capital. But in addition to commodity, PGW charges for distribution costs as a function of consumption, at about 38¢/Ccf for MS, 62¢ for residential GS, and about 52¢/Ccf for PHA and the non-residential GS classes. Since distribution costs are almost all fixed in the short term, every Ccf of gas that a customer does not use due to an energy-efficiency and conservation program reduces PGW's earnings and cash flow.

The better PGW does at reducing its customers' energy usage and bills, the worse off PGW would be under current ratemaking. This disincentive remains one of the major barriers to more effective energy policy in many states.

Q: How does PGW propose to resolve this conflict?

A: Philadelphia Gas Works proposes to recover its lost revenues for all customers, other than those in the Customer Responsibility Program (CRP), through the ECRM. Due to the operation of the CRP, efficiency measures delivered to CRP customers will not result in reductions in the participating customer's bill, but will instead reduce the Universal Service Surcharge borne by all non-CRP firm customers. Those revenues will be permanently lost to PGW, and will increase until the next rate proceeding, when rates will be reset and the losses will start to accumulate once more.

Q: How would the lost-revenue portion of the ECRM work?

A: The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency and conservation program:

1. Count the number of measures installed under the program.
2. Estimate the annual sales effects of each measure.
3. Estimate the percentage of the savings that would have occurred without the program, and that therefore do not reflect any program-related revenue loss.[4]
4. Estimate the extent of spillover from the program to non-participants, such as by increasing supply of efficient equipment in warehouses and stores.
5. Determine the rate per Ccf for the sales reduction, which may require, for example, tracking the number of participants in a boiler program who are on residential Rate GS, public-housing Rate GS, commercial Rate GS, Rate PHA, and Rate MS.
6. Compute when the savings from each measure would start, given both the installation schedule and the seasonality of load.
7. Compute the resulting lost revenues.

Q: What factors would be considered in estimating the sales effects of each measure?

A: The estimated effect on sales may depend on the following factors:

- the size of the equipment affected, such as the volume of the water heater or the Btu output rating of a furnace;
- building size;

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4 The participants who would have invested in efficiency without the program are often called "free riders." That terminology incorrectly suggests that they are somehow getting a better deal than other participants.

- household size, especially for water heaters, dishwashers, and clothes washers;
- pre-measure usage;
- efficiency of the rest of the system, such as the effect of the building envelope on the sales reduction from a more-efficient heating system.

Q: Would all of these variables be determined for each installation?

A: Not all of them. PGW will establish a tracking system to record the number of rebates and installations, information on the size and model number of equipment installed, customer rate class, and other detailed data. Variables that would not be feasible to track for each installation (such as household size in a rebate program) would be determined from limited samples of participants.

Q: Is this approach used in other jurisdictions?

A: Yes. Lost-revenue-adjustment mechanisms are used for electric and/or gas utilities in Ontario, Massachusetts, Connecticut, Vermont, Ohio, Kentucky, and Indiana, Maryland, New Jersey, and New York.

Q: Has PGW developed detailed protocols for the tracking system and the estimation of lost revenues?

A: Not yet. PGW intends to develop the tracking system and the lost-revenue formulas in parallel with implementation of the efficiency programs. In my experience, the development of programs, tracking system, and lost-revenue-estimation procedures generally occur in parallel.

This process will probably be most-effectively pursued through a collaborative effort with the Public Utility Commission Staff, the Consumer Advocate, the Office of Small Business Advocate, and other parties with expertise in energy-efficiency monitoring and evaluation. In particular, it is important to resolve cooperatively the lost-revenue inputs to the extent possible.

Arguing about these issues in an ECRM proceeding may push PGW and other parties into positions based on the lost-revenue litigation, rather than identifying the most-effective measures and delivery mechanisms to reduce energy consumption, and on the best estimates of savings from those measures and mechanisms.

Q: Would the lost-revenue computation be reset at some point?

A: Yes. In each rate proceeding, a new projection of pro-forma revenues is used to set rates. Accordingly, any lost-revenue amount in the ECRM would be eliminated at the effective date of the new rates.

Q: What are the alternatives to lost-revenue recovery?

A: Were the lost-revenue recovery not implemented, the alternatives would be as follows:

- Continue with the existing ratemaking process;
- Conduct annual rate cases, projecting sales based on DSM underway;
- Roll all distribution costs into customer charges, so that PGW's distribution revenues are independent of sales;
- Implement a revenue-stabilization mechanism;
- Minimize investment in conservation.

Q: What would be the consequences of maintaining the current approach to ratesetting for PGW?

A: Promoting energy efficiency in that case may result in financial distress for PGW, forcing it to curtail programs pending a rate increase. In the absence of those programs, customer gas bills would be greater than necessary.

Q: What would be the consequences of conducting annual rate cases and projecting sales to reflect DSM plans?

A: These continual rate cases would impose large burdens on PGW, the Commission, and other parties. The demands of a rate case compete for the attention of PGW management, and hence impede their ability to implement improvements and innovations, not to mention routine obligations. PGW may also be forced to slow its implementation of energy-efficiency and conservation programs to live within the revenues projected in the rate case and used to set distribution rates.

Q: What would be the effect of rolling all distribution costs into customer charges?

A: That approach would violate the principle of cost causation, since a significant portion of PGW's distribution costs are driven by load levels. It would also eliminate customers' opportunity to reduce their distribution bills, seriously affect the smaller customers in each rate class by materially increasing their bills, and charge very different amounts to customers based solely on their classification as commercial or industrial customers.

Q: How would a revenue-stabilization mechanism operate?

A: A revenue-stabilization or decoupling mechanism would compare actual revenues to a target revenue level, and adjust rates to flow the difference to PGW or its customers.

Q: Would a revenue-stabilization mechanism have any advantages compared to the proposed lost-revenue mechanism?

A: Yes, least three. First, a revenue-stabilization mechanism would eliminate any weather-related over- and under-collections not captured by the existing weather adjustment (e.g., the effects of wind speed, cloud cover, snow cover, etc.).

Second, the projection of sales in a rate proceeding would no longer be of great import. Were the forecast overstated, the revenue-stabilization charge would increase; if the understated, the revenue-stabilization charge would decrease and perhaps even become negative. Removing the sales forecast from a rate proceeding should reduce the cost and burden for PGW, the Commission Staff, the Consumer Advocate, the Office of Small Business Advocate, and other parties.

Third, lost-revenue adjustments also generally cannot account for PGW's role in providing information and other indirect support for energy-efficiency and conservation investments, for the effects of market-transformation programs, or the effects of other programs encouraged or supported by PGW. In the case of programs operated by electric companies or various government agencies, PGW's provision of billing data, customer contacts, and other services may be critical to success of the programs. The success of PGW in supporting those programs may undermine PGW's financial stability, even with a lost-revenue adjustment. A revenue-stabilization mechanism does not differentiate among the possible reasons for differences between target and actual revenues, and hence would protect PGW's distribution revenues from the effect of efficiency and conservation programs, regardless of who administers those programs.

Q: Do other gas utilities have revenue-stabilization mechanisms in place?

A: Yes. Some thirteen states have some sort of revenue-stabilization mechanism in place for a total of nearly thirty utilities. In California, these provisions have been in place for more than 25 years. In addition, the Massachusetts Department of Public Utilities has approved revenue stabilization for all utilities in that state, pending individual filings, and the Nevada PSC has submitted proposed revenue-stabilization regulations for legislative review.

Q: Do any of the jurisdictions near Pennsylvania use revenue-stabilization mechanisms?

A: Yes. In New Jersey, for example, South Jersey Gas and New Jersey Natural Gas reached a settlement with the Rate Counsel and Board Staff, establishing (among other things) a set of conservation programs and revenue stabilization, with target revenues set at the number of customers times baseline revenue per customer for each class. The utilities' collection of revenues under this Conservation Incentive Program is limited to the effects of weather plus demonstrated savings in gas costs from release of excess capacity, reduced purchases of gas, avoided increases in fixed supply costs, and other reductions.

Q: Why are you not proposing a revenue-stabilization mechanism?

A: Philadelphia Gas Works chose to propose the more-conservative lost-revenue approach to increase the chances of consensus agreement on lost-revenue recovery.

V. Estimate of Lost Revenues

Q: Please describe your analysis of the impact of DSM spending on lost revenues, average rates, and bills.

A: My analysis estimates average rates and bills for each major customer class for a base scenario that assumes no new DSM spending, and then estimates the effect on class-average rates and bills from forecasted DSM spending and associated reductions in customer usage. I forecast average rates and bills, both with and without DSM-related impacts, over a five-year period starting in fiscal year 2010.

Q: How do you derive the without-DSM average rates and bills for each customer class?

A: I calculate without-DSM average rates and bills based on the Company's current budget forecast of revenues, sales, and number of customers. For each customer class, and for each fiscal year from 2010 through 2014, the average bill is calculated as revenues from firm heating, non-heating, transport customers divided by the number of those customers. Likewise, the average rate is calculated as class revenues from firm customers divided by sales to those customers.

Q: How do you account for the effects of DSM spending on average rates and bills?

A: I reflect these effects on average rates and bills by adjusting the forecast of revenues and sales to account for DSM-related expenditures and savings. Specifically, I make the following adjustments to revenues for each customer class and for each forecast year:

- *increase,* to reflect the estimate of DSM-program spending for that class and year;
- *decrease,* to account for reductions in gas-commodity costs from DSM-related savings estimated for that class in that year.

In addition, I adjust forecasted revenues to reflect changes in recovery of the Universal Service Charge from non-CRP customers that result from DSM spending on CRP customers. For the purposes of this calculation, I assume that DSM spending on CRP customers has no effect on the amount of revenues recovered from those customers. Instead, I adjust the USC revenues recovered from non-CRP customers to reflect the following factors:

- recovery of direct DSM spending on CRP customers,
- reductions in gas-commodity costs attributable to CRP DSM savings,

- reductions in CRP distribution-charge revenues that are recovered from non-CRP customers through the USC.[5]

Finally, I reduce forecasted sales for each customer class and forecast year by estimated DSM-related savings. Average rates and bills with DSM are then calculated in the same fashion as in the without-DSM case, but using the revenue and sales forecasts as adjusted to reflect the effects of DSM spending.

Q: **Please summarize your estimates of lost revenues.**

A: Table 3 provides those estimates, assuming no rate case occurs through 2014-15. The "total not including CRP" would be recovered through the ECRM, while PGW would absorb the remainder of the "total" line.

Table 3: Summary of Estimated Lost Revenues

Fiscal Year	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**2014–15**
Non-Low-Income Residential Customer	$96,772	$505,745	$1,293,167	$2,298,727	$3,008,409
CRP (Low Income)	469,354	1,312,844	2,082,352	2,880,463	3,418,393
Commercial Customers	17,301	88,629	230,301	448,013	626,875
Industrial Customers	405	1,821	5,260	12,745	19,825
Municipal Customers	2,742	29,244	86,720	154,436	199,807
Housing Authority—Rate GS	333	1,814	4,492	7,688	9,925
Housing Authority—Rate PHA	939	5,107	12,647	21,648	27,947
Total	$587,846	$1,945,203	$3,714,939	$5,823,720	$7,311,181
Total Not Including CRP	$118,491	$632,359	$1,632,587	$2,943,257	$3,892,788

Q: **Is PGW claiming these amounts for recovery in its ECRM?**

A: No. These are estimates based upon the proposed DSM program and current revenue projections. If and when PGW's DSM program is approved, PGW will submit a specific lost-revenue-calculation protocol and a specific proposed level of lost revenues, based upon the program as approved. PGW will then track its

5 These revenue reductions are in fact lost revenues attributable to CRP DSM savings. However, these lost revenues will not be recovered through the lost-revenue surcharge.

lost revenues and will submit adjustments to the projections based on actual results.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

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"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

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"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop; April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C.; October 21 1991;

"Least Cost Planning and Gas Utilities." Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context," NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

"Increasing Market Share Through Energy Efficiency." New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies," District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages," New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans," Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

"Power Plant Performance," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

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District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **MEFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **New Mexico PSC** 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7 1986.

Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Massachusetts Division of Insurance** 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vermont PSB** 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vermont PSB** 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

    Prudence of BECo's decision of spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **MDPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24 1989. Rebuttal, October 3 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

    Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

    Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

    Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

    Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Maryland PSC** 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Virginia State Corporation Commission** PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **MDPU** 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **South Carolina PSC** 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Maryland PSC** 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **MDPU** 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Florida PSC** 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Florida PSC** 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Pennsylvania PUC** I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **South Carolina PSC** 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **MDPU** 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **South Carolina PSC** 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **North Carolina Utilities Commission** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Maryland PSC** 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **North Carolina Utilities Commission** E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113.**Michiga n PSC** U-10102; Detroit Edison Rate Case; Michigan United Conservation
A. Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

DSM planning, program designs, potential savings, and avoided costs.

115. **Michigan PSC** U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vermont PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Florida PSC** 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vermont PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Michigan PSC** U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Michigan PSC** U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **New Jersey Board of Regulatory Commissioners** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Michigan PSC** U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Michigan PSC** U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **North Carolina Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **DCPSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Maryland PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

135. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Maryland PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. A. **MDPU** DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **MDPU** DPU 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **MDPU** DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Maryland PSC** 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **New Hampshire PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vermont PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **MDPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vermont PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **MDPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **MDTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

154. **Vermont PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **MDTE** 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vermont PSB** 6107, Green Mountain Power rate increase, Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **MDTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Maryland PSC** 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Maryland PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Maryland PSC** 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Connecticut DPUC** 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Connecticut DPUC** 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Washington UTC** UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Connecticut DPUC** 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Connecticut DPUC** 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Virginia PSC** 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ontario Energy Board** RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Connecticut DPUC** 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the CDPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Connecticut Superior Court** CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the CDPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ontario Energy Board** RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Connecticut DPUC** 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ontario Energy Board** RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **NY PSC** 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Connecticut DPUC** 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **MDTE** 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Connecticut DPUC** 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vermont PSB** 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **New Jersey BPU** EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **New Jersey BPU** GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Connecticut DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; Supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **New Jersey BPU** EX01050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **NY PSC** 00-E-1208; Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **MDTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **New Jersey BPU** EM00020106; Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vermont PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Connecticut Siting Council** 217; Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vermont PSB** 6596; Citizens Utilities Rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Connecticut DPUC** 01-10-10; United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Connecticut DPUC** 01-12-13RE01; Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Connecticut DPUC** 03-07-02; CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Connecticut DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vermont PSB** 6596; Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** Case 03-2144-EL-ATA; Ohio Edison , Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. Direct February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **NY PSC** 04-E-0572; Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ontario EB** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **MDTE** 04-65; Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; Supplemental January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **NY PSC** 04-W-1221; rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **NY PSC** 05-M-0090; system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Maryland PSC** 9036; Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Connecticut DPUC** 05-07-18; financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. Direct September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, April 2006.

     Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Connecticut DPUC** Docket 05-10-03; Connecticut L&P; time-of-use, interruptible and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

     Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ontario Energy Board** Case EB-2005-0520; Union Gas rates; School Energy Coalition. Evidence, April 2006.

     Rate design related to splitting commercial rate class into two classes: new break point, cost allocation, customer charges, commodity rate blocks.

215. **Ontario Energy Board** Case EB-2006-0021; natural gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

     Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Indiana Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

     Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

     Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Pennsylvania PUC** Docket No. R-00061366, et al.; rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

     Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Connecticut DPUC** 06-01-08; Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings September and October 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Connecticut DPUC** 06-01-08; United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **NY PSC** Case No. 06-M-1017; policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Connecticut DPUC** 06-01-08; procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **PUCO** Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **NY PSC** Case 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. Direct, March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alberta EUB** 1500878; ATCO Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. Direct, May 2007

Direct assignment of distribution costs to streetlighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **NY PSC** Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Manitoba PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59, proposed Brockton Power Company plant; Alliance Against Power Plant Location. Direct, March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **CDPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ontario EB-2007-0905,** Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah PSC 07-035-93,** Rocky Mountain Power Rates; Utah Committee of Consumer Services. Direct, July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ontario EB-2007-0707,** Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **NY PSC** Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **CDPUC 08-07-01**, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Manitoba PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Maryland PSC** 9036; Columbia Gas rates; Maryland Office of People's Counsel. Direct, January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vermont PSB** 7440; extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239 **Nova Scotia Review Board** P-884(2), Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240 **Nova Scotia Review Board** P-172, proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Connecticut Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242 **Mass. DPU** 09-39, NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243 **Utah PSC** Docket No. 09-035-23, Rocky Mountain Power rates, Utah Office of Consumer Services. October 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

Exhibit PLC-2

Forecast of Philadelphia Gas Works Avoided Gas Costs

By Paul Chernick

The economic evaluation of an energy-efficiency measure requires an estimate of the measure's benefits. The major benefit of gas energy-efficiency programs is the reduction of gas use and associated costs to customers. Those avoided costs may be passed on to customers by the utility, third-party suppliers, or both, but they are all eventually paid by customers.

Electric avoided costs are often computed for a number of cost drivers, such as summer and winter contribution to system peak load, and on seasonal energy use for on- and off-peak periods. In the cost-benefit computation, analysts estimate the effect of a proposed measure or program on each of the cost drivers. The benefit of the energy-efficiency proposal is then estimated by multiplying the energy savings for each cost driver by the per-unit avoided cost for that driver, and adding up the benefits for all the drivers. This approach works well for evaluation of electric energy-efficiency programs, simplifying the costs of serving loads for 8,760 hours to a few cost drivers, which can be estimated for the wide variety of electric end uses (e.g., residential and commercial space heating, space cooling, ventilation, water heating, refrigeration, indoor and outdoor lighting, clothes drying, cooking, computers and other plug loads, as well as a range of industrial loads).

Like most detailed analyses of avoided gas costs, this study's calculation of avoided costs is structured differently than that usually used to estimate electric avoided costs. Planning and procurement for natural gas is primarily concerned with daily loads, rather than annual loads, so there are fewer load shapes. There are also fewer end uses for gas than electricity, since very little gas is used for lighting, refrigeration, or residential air conditioning, and no gas is used for computers or ventilation. Hence, it is feasible to compute avoided costs for the load shapes of the few gas end uses. In the cost-benefit analysis, the benefit of each energy-efficiency measure can be estimated as the measure's annual savings times a single load-specific avoided cost.

This load-shape approach to defining avoided costs allows for distinctions between the costs of different end uses that impose different costs, even for similar seasonal usage levels. An end use that does not vary with weather, such as cooking or clothes drying, may use the same amount of gas in the winter as a heating boiler, but the gas to serve the boiler will be more expensive. The boiler will predictably use more gas on very cold days, when gas is most expensive, and less on mild days, when gas is relatively cheap. Serving the boiler requires the reservation of enough pipeline capacity to meet load on typical cold days, and the construction of local transmission-and-distribution capacity and supplemental gas supplied to meet load on extraordinarily cold days. The boiler will use more gas on cold days, when regional gas demand is high and prices are high. The development of avoided cost by load shape allows for the reflection of these differences between loads even within a season or a month.

This estimate of avoided gas costs comprises the following three parts:

- *Commodity:* The market prices of gas delivered to a utility's citygate in a normal year
- *Peaking capacity:* The costs of local capacity to cover the difference between normal and design-peak conditions
- *Local transmission and distribution* (T&D): The utility's cost of building, operating and maintaining the high-pressure transmission and lower-pressure distribution system in its service area

Commodity Cost

I forecast the monthly delivered gas price to the PGW citygate for gas delivered evenly over the month, as the sum of the price of gas delivered to the Henry Hub and the price basis (the price different) from Henry Hub to Zone M3 of the Texas Eastern Transmission (TETCo) pipeline, which includes the PGW citygate.

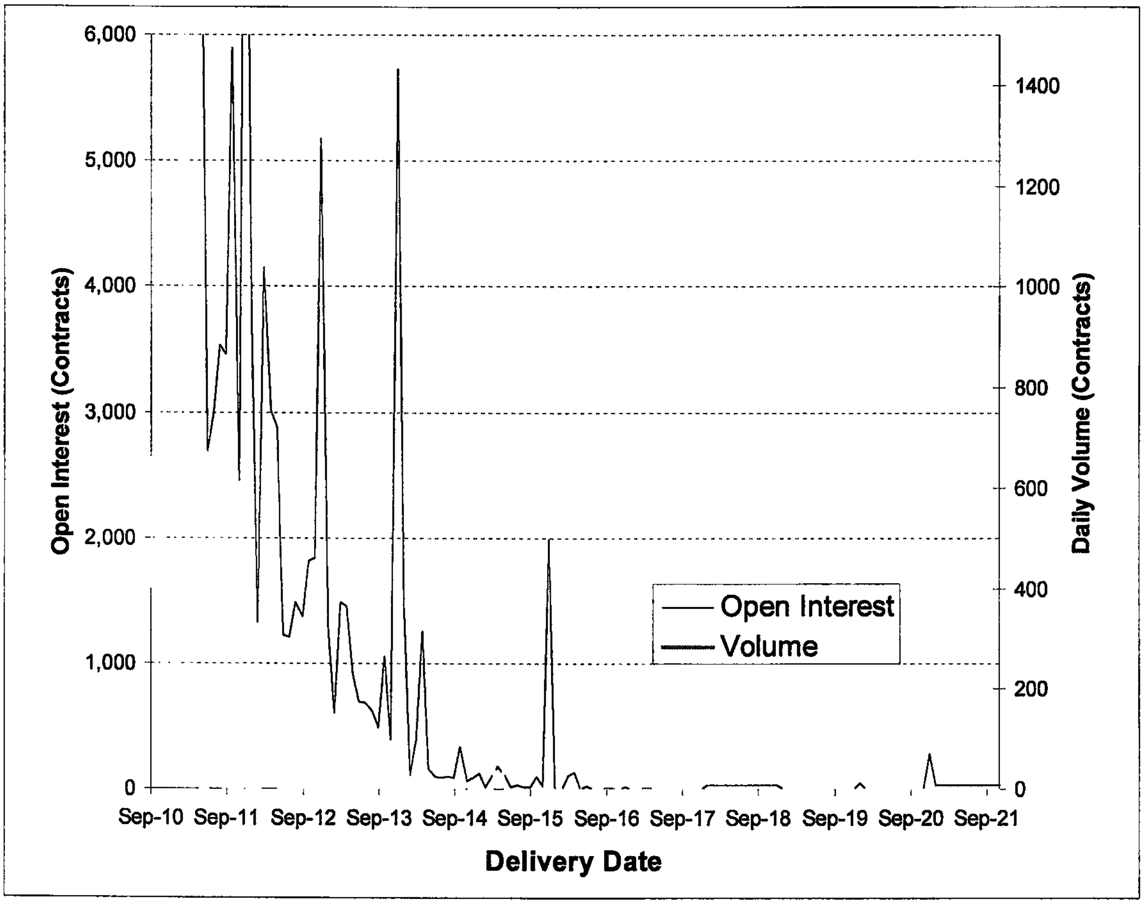
For the period from September 2010 through August 2014, I computed the monthly prices as the sum of the NYMEX forward price for Henry Hub (NYMEX contract NG) and the TETCo basis forward (NYMEX contract NX). Since NYMEX reports TETCo forwards only through July 2013, I assumed that the basis would remain at the April–July 2013 value through October 2013,[1] and that the basis in each subsequent month would be equal to the basis in the same month one year earlier, in real terms.

After 2014, the trading of NYMEX Henry Hub futures becomes quite thin. On September 28, 2009, for example, 115,000 Henry Hub contracts (of 10 billion Btu each) were outstanding for the 2010/11 gas year, but only about 1,200 contracts

[1]The TETCo basis forwards in each year 2010 through 2012 are equal throughout the April–October period.

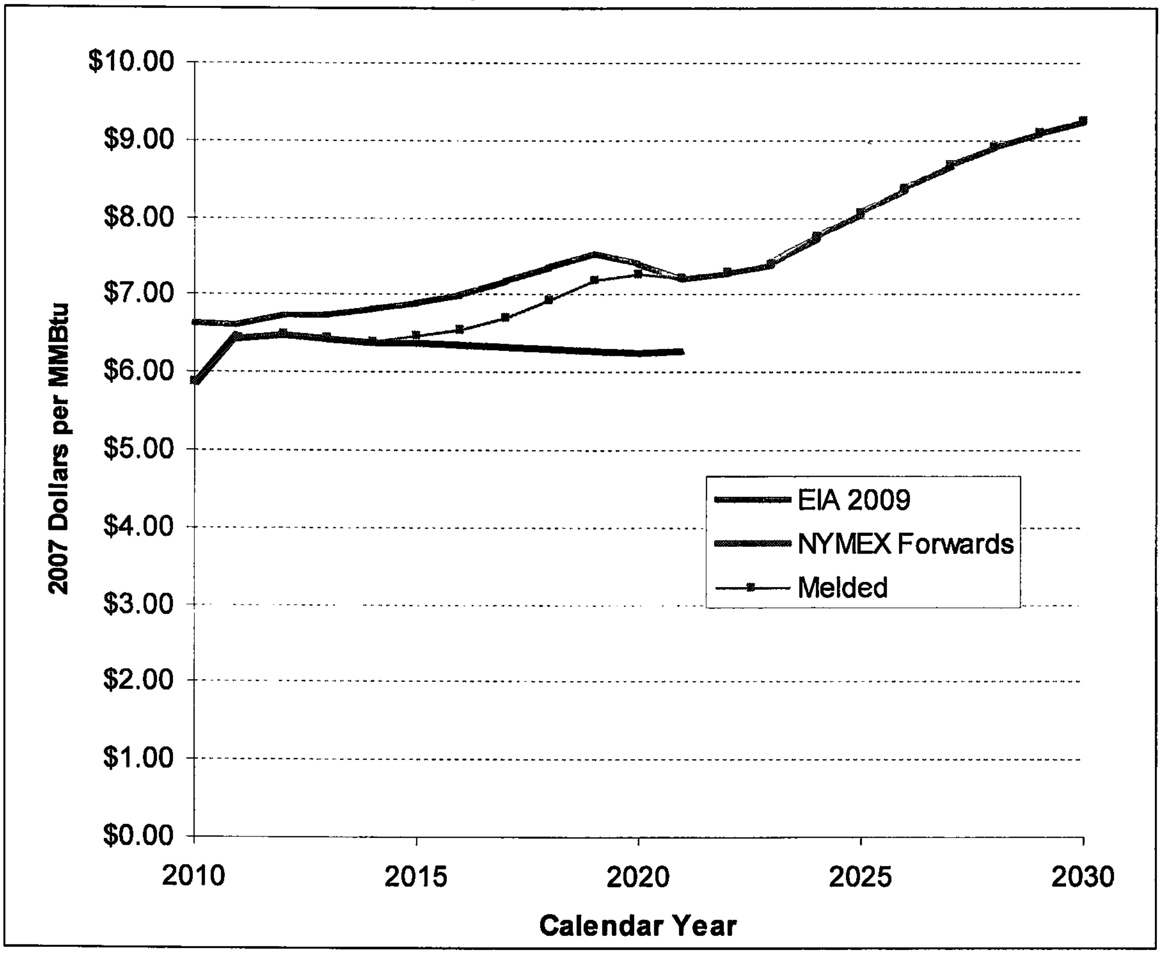
for 2014/15. On many days, no contracts are traded for most months beyond 2010/11. See Figure 2-1.

Figure 2-1: NYMEX Henry Hub (NG) Forward Market, September 28, 20091



Given the thin trading in the Henry Hub contract starting in 2014, I do not have much faith that the NYMEX prices are meaningful in the later years. I therefore put increasing weight on the forecast of Henry Hub prices in the 2009 Annual Energy Outlook published by the Energy Information Administration (EIA 2009, 32, Table A13). From gas years 2014/15 through 2021/22, I trend my projection of the Henry Hub gas price from 100% reliance on the NYMEX forwards to 100% reliance on EIA. After 2011/22, I use EIA's gas-price projection. See Figure 2-2.

Figure 2-2: Projections of Henry Hub Gas Prices



From these forwards, I computed annual commodity costs for the following three load shapes:

- *baseload,* including industrial processes, cooking, and clothes drying, modeled as using the same amount of gas every day.
- *space heating,* modeled as using gas each day in proportion to daily heating degree days (HDD).
- *water heating,* modeled as a mix of baseload and space-heating load. This approximation reflects the observation that gas usage by water-heating customers rises in the winter months, probably as a combination of higher standby losses and warmer water temperatures for baths, showers, and washing.

While gas utilities do not purchase a large portion of their supply in the daily spot market, the short-term market—where utilities can procure gas to meet higher-than-expected load, or sell off gas when their supplies exceed their needs—determines the value of the gas. Every dekatherm of gas that a PGW consumer does not use is one more dekatherm available to someone in the spot market who is willing to pay the spot price for that gas. Depending on the gas-supply situation and contracts of the utility (or gas supplier), the utility may avoid buying gas from the spot market, or sell more gas into the spot market, or reduce its use of some longer-term contract.

In the longer term, annual and multi-year contracts should average near the spot prices for the same time periods. Estimating the effect of specific load reductions on the supply portfolio and costs of any particular utility or gas supplier is complicated, since the calculation would entail modeling purchases, sales and usage of a variety of gas supplies, pipeline capacity, storage resources, and supplementary resources. This approach would also require non-public data from competitive gas suppliers. The spot-market price is a reasonable estimate of the resource benefit from reduced commodity use.

Baseload Commodity

For baseload end uses, where use of gas does not vary with weather or the season, the analysis weights the forecast monthly gas price by the number of days in the month.

Space-Heating Commodity

The cost of commodity for space heating varies from the cost of baseload in two ways. First, the amount of gas used varies among months, and is concentrated in the higher-cost winter months. Second, within each month, space heating uses more gas on the colder days, when gas tends to be more expensive than the average for the month.

For the first factor, the monthly percentage the study assumed that the monthly use of gas for space heating is proportional to the monthly sum of daily heating degree days (HDDs). Heating degree days are the difference between the day's average temperature and a base temperature, at which space-heating use is assumed to be zero. That base temperature, or balance point, is lower than the temperature maintained by the thermostat, since the building is warmed by sun shining in the windows and by interior gains (waste heat) from lights, appliances, equipment, and people.

I used the monthly average HDDs with a base of 65° F for 1978–2007 published by NOAA (2007).

The second factor, the effect of the intra-month correlation of price and load, reflects the fact that heating loads use more gas on colder days within each month, and that prices tend to be higher on cold days.[2] This correction was computed as the typical ratio of the heating-load-weighted market price to the average daily price for the month. Since the NYMEX prices are for gas delivered evenly over the month, multiplying that ratio by the NYMEX-based price forecast results in an estimate of the price of gas for heating load in the month.

Of course, gas prices vary due to factors other than the current day's temperature in Philadelphia, including the following:

- wind and sunshine on that day, since heating load will be greater on a cloudy, windy 40°F day than a sunny calm day with the same air temperature.
- weather in other parts of North America. A cold snap in California will drive up wellhead prices in Texas and Alberta, and hence prices for deliveries to Pennsylvania. Cold temperatures in New England or New York raise not only wellhead prices but also market prices for delivery to New York citygates. Conversely, mild weather elsewhere can moderate prices in Philadelphia, even when it is cold in Philadelphia.
- weather on other days. High gas demand in earlier days of the same month, or in earlier months, will tend to deplete storage and push prices higher. Forecasts of cold weather in coming days and weeks will tend to push up price before the cold front hits, as users scramble to put gas into storage.
- The amount of gas in storage, which depends on the weather, other gas demands over the previous year or so, market participants' guesses regarding price tends, and other factors.
- demand for gas for electric generation, which varies during the month with oil prices and outages of coal and nuclear plants and between years as load grows and supplies change.
- gas-production capacity, which changes within winter months primarily due to freeze-ups of gas wells in producing areas, but changes significantly between years due to depletion and new additions (and sometimes hurricanes).

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[2]The utility or a gas supplier can meet load in those high-load high-priced days with spot purchases, by reserving storage and associated transportation to the citygate, or by reserving additional pipeline capacity directly to the citygate. All these approaches impose costs that would not be needed for a load that was constant across the days of the month.

For this study, the intra-month price ratio was computed for each calendar month using data for each of the last two gas years, 2006/07 and 2007/08. The analysis computes the ratio of load-weighted to average monthly price for each month.

Equation 1. Intra-Month Heating Price Ratio.

$$\text{intra-month heating price ratio} = \frac{\left[\dfrac{\sum_{month} HD_{day} \times P_{day}}{\sum_{month} HD_{day}}\right]}{\left[\dfrac{\sum_{month} P_{day}}{\#\text{ days in the month}}\right]}$$

where HD_{da} = heating degree-days for the day
P_{day} = delivered price for the day

The ratios tend to be highest in the winter and close to 1.00 in the shoulder months.

The heating commodity cost for each year is the sum across months of the following product:

NYMEX monthly forward × monthly HDD % × intra-month price ratio

The annual heating commodity cost is significantly greater than the annual baseload commodity cost. The annual residential heating avoided cost, averaged over the period 2006–2025, is about 17% greater than average annual baseload price. These differences can largely be explained by the fact that most of the heating usage is in the high-priced months of January, February, and December.

Water-Heating Commodity

My previous experience indicates that water-heating load is largely equal across months and days, but rises somewhat in colder weather. The observed load shape is probably attributable to a combination of higher standby losses and increased usage (for longer, hotter showers and baths, and warmer water for hand-washing) in cold weather. I assumed that the avoided water-heating commodity cost equals a 75% weighting of the baseload avoided cost and 25% weighting of space-heating avoided cost.

Commodity-Cost Summary

Figure 2-3 shows avoided commodity costs for the three load shapes. The relationships among the prices for the various load shapes are as expected. The heating cost is higher than the water-heating cost, which is higher than the baseload cost.

The average costs of utility gas supplies, which serve large amounts of heating load, tend to be much higher than the flat year-round gas supplies reflected in the baseload commodity costs. The average avoided commodity cost will similarly be more expensive than the avoided commodity cost for a flat year-round gas supply.

Peaking-Capacity Cost

In addition to buying and delivering the gas required in a normal year, a gas utility must be prepared to meet much higher loads on an extremely cold (design) day, through a cold snap, or in a very cold winter season. The prices for gas in a normal year do not include the costs of reserving capacity and supplies to meet design conditions. Those design loads are normally met by local storage (such as liquefied natural gas) and/or peaking off-system storage and associated transportation. The commodity costs reflect the costs of normal weather, while the peaking supplies reflect the resources maintained to meet design weather.

For PGW, design conditions include both a design day with 65 HDD (last experienced on January 17, 1982) and a design winter with heating loads approximately 19.4% more than normal. I estimated the cost of reserves to meet those conditions as the price of PGW's contracts supporting its most expensive storage supply (Equitrans) times the percentage increase in heating load between normal and design winters. I took the fixed cost of the Equitrans supply as \$2.40/Dth, from Schedule SDS-8 of PGW'S Supporting Documentation filed on June 2008. Exhibit PLC-3 shows my computation of normal heating sendout (42.5 million Dth) and the design-winter sendout increment (8.3 million Dth). 0.194 Dth of peaking supply at \$2.40/Dth of peaking results in a peaking-reserve cost for heating load of about \$0.50/Dth; see Figure 2-3.

Since baseload has no increment of sendout on the design peak over average conditions, it would not have any peaking capacity charges.

Avoided Transmission-and-Distribition Cost

As peak loads grow, local distribution companies need to expand their internal transmission and distribution systems by adding parallel mains, looping, and increasing operating pressures, and increasing the size of new and replacement lines. The expenditures vary across each utility's service area and over time. Most utilities will include some areas in which relatively small increments of load require expensive upgrades, along with other load areas with excess capacity for many years resulting in no expansion costs. Marginal or avoided T&D costs are therefore generally estimated by comparing growth-related costs to peak load growth over a period of several years.

Since PGW expects sales to continue to decline and does not expect sales growth in the vast majority of its service territory, the opportunities for load reductions to reduce T&D investments will be quite limited. I did not include any avoided T&D costs in these avoided-cost estimates.

Figure 2-3: Computation of Avoided Costs, Part 1

	Ratio of weather-adj to simple average	Percent of normal HDD	percent of days	Year Starting 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Sep	0.983	0.8%	8.2%	6.648	7.157	7.334	7.474	7.614	7.765	7.906	8.047	8.208	8.355	8.476	8.618
Oct	1.045	5.7%	8.5%	6.805	7.247	7.414	7.554	7.699	7.850	7.991	8.132	8.293	8.440	8.566	8.703
Nov	1.006	11.5%	8.2%	7.190	7.527	7.612	7.710	7.859	8.008	8.152	8.306	8.470	8.625	8.780	8.915
Dec	1.012	18.0%	8.5%	8.147	8.419	8.489	8.615	8.771	8.932	9.099	9.277	9.455	9.638	9.847	10.011
Jan	1.054	21.4%	8.5%	9.152	9.399	9.459	9.600	9.782	9.959	10.152	10.346	10.546	10.747	10.973	
Feb	1.027	18.0%	7.7%	9.075	9.337	9.399	9.534	9.714	9.891	10.082	10.275	10.474	10.673	10.893	
Mar	1.027	14.3%	8.5%	7.905	8.144	8.202	8.312	8.478	8.634	8.805	8.977	9.159	9.331	9.519	
Apr	1.009	7.6%	8.2%	6.947	7.134	7.274	7.379	7.535	7.666	7.832	7.993	8.135	8.281	8.443	
May	1.000	2.4%	8.5%	6.902	7.094	7.229	7.334	7.495	7.626	7.792	7.953	8.095	8.241	8.398	
Jun	1.000	0.3%	8.2%	6.972	7.164	7.299	7.419	7.575	7.706	7.872	8.033	8.175	8.316	8.468	
Jul	1.000	0.0%	8.5%	7.057	7.244	7.379	7.514	7.665	7.806	7.962	8.123	8.265	8.406	8.553	
Aug	1.000	0.0%	8.5%	7.127	7.304	7.444	7.584	7.735	7.876	8.022	8.183	8.330	8.456	8.603	
Simple average				7.487	7.757	7.871	7.996	8.153	8.303	8.465	8.63	8.793	8.951	9.119	
HDD-weighted average				8.396	8.674	8.756	8.883	9.054	9.220	9.398	9.579	9.764	9.948	10.148	

Figure 2-3 continues on the following page.

Figure 2-3 Continued: Computation of Avoided Costs, Part 2

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
EIA (2009) HH Real Escalation					0.4%	1.2%	2.0%	3.0%	3.8%	1.9%	−0.1%	0.4%	1.4%	3.8%	4.3%	3.8%	3.6%	3.0%	2.2%	1.9%	0.6%	2.2%			
Commodity Price Projection[a]																									
Simple average	7.487	7.757	7.871	7.996	8.188	8.441	8.764	9.183	9.685	10.049	10.238	10.483	10.824	11.419	12.096	12.761	13.440	14.083	14.652	15.196	15.584	16.210	16.534	16.864	17.202
HDD-weighted average	8.396	8.674	8.756	8.883	9.097	9.378	9.737	10.203	10.760	11.164	11.375	11.647	12.026	12.687	13.439	14.178	14.932	15.646	16.279	16.883	17.315	18.009	18.370	18.737	19.112
Avoided Peaking Cost																									
Heating[b]	0.516	0.526	0.536	0.547	0.558	0.569	0.581	0.592	0.604	0.616	0.628	0.641	0.654	0.667	0.68	0.694	0.708	0.722	0.736	0.751	0.766	0.781	0.797	0.813	0.829
Totals Nominal Dollars																									
Baseload	7.49	7.76	7.87	8.00	8.19	8.44	8.76	9.18	9.68	10.05	10.24	10.48	10.82	11.42	12.10	12.76	13.44	14.08	14.65	15.20	15.58	16.21	16.53	16.86	17.20
Space Heating	8.91	9.20	9.29	9.43	9.66	9.95	10.32	10.79	11.36	11.78	12.00	12.29	12.68	13.35	14.12	14.87	15.64	16.37	17.02	17.63	18.08	18.79	19.17	19.55	19.94
Water Heating	7.84	8.12	8.23	8.35	8.55	8.82	9.15	9.59	10.10	10.48	10.68	10.93	11.29	11.90	12.60	13.29	13.99	14.65	15.24	15.81	16.21	16.85	17.19	17.54	17.89
Totals 2008 Dollars																									
Baseload	7.20	7.31	7.27	7.24	7.27	7.35	7.48	7.68	7.94	8.08	8.07	8.10	8.20	8.48	8.81	9.11	9.41	9.67	9.86	10.03	10.08	10.28	10.28	10.28	10.28
Space Heating	8.57	8.67	8.58	8.54	8.57	8.66	8.81	9.03	9.32	9.47	9.46	9.50	9.61	9.92	10.29	10.62	10.95	11.24	11.45	11.63	11.70	11.92	11.92	11.92	11.92
Water Heating	7.54	7.65	7.60	7.57	7.60	7.68	7.81	8.02	8.29	8.43	8.42	8.45	8.55	8.84	9.18	9.49	9.80	10.06	10.26	10.43	10.48	10.69	10.69	10.69	10.69

[a]For 2010–2013, projection from NYMEX. For 2012–2034, 90% escalated at HH, plus general inflation.

[b]For each year, fixed storage cost per Dth × (incremental design Dth ÷ normal-weather heating Dth), computed as follows:

- Fixed storage costs at $2.40/Dth (from SDS-8);
- Design sendout at 0.194 incremental Dth per Dth of normal-weather heating load: Normal Heating Sendout of 42.5 MM Dth ÷ Design Heating Increment of 8.26 MM Dth. See Exhibit PLC-3.

Works Cited

EIA. 2009. "An Updated Annual Energy Outlook 2009 Reference Case Reflecting Provisions of the American Recovery and Reinvestment Act and Recent Changes in the Economic Outlook" SR-OIAF/2009-03. Washington: Energy Information Administration.

NOAA. 2007. "2007 Local Climatological Data: Annual Summary With Comparative Data, Philadelphia, Pennsylvania (KPHL)" ISSN 0198-4535. Washington: National Oceanographic and Atmospheric Administration.

Exhibit PLC-3: Peaking-Supply Requirement

	Total Volume	Interruptible Sales	Firm Sales & Transport *Total*	Firm Sales & Transport *Per Day*	Units	Source
Computation of Baseload						
Sep-08	1,150,924	30,262	1,120,662	37,355	Mcf sales	GCR-3
Jul-09	1,272,769	22,420	1,250,349	40,334	Mcf sales	GCR-3
Aug-09	1,225,968	22,479	1,203,489	38,822	Mcf sales	GCR-3
Average				38,837	Mcf sales	
Annual Baseload			14,175,562		Mcf sales	Summer daily average × 365
Total Annual Normal Sendout						
Total Firm	54,991,226	1,396,648	53,594,578		Mcf sales	GCR-3
Firm Heating			39,419,016		Mcf sales	Total - Baseload
			40,838,101		Dth sales	1.036
			42,495,423		Dth sendout	0.961
Incremental Requirement, Normal to Design						
Design	68,284,128				Dth sendout	SDS-4, p. 1
Normal	60,025,061				Dth sendout	SDS-4, p. 1
Increment	8,259,067				Dth sendout	

Schedules CGR-3 and SDS-4 are from Volume I of supporting documentation filed with the Philadelphia Gas Commission by PGW in June of 2008.