ORIGINAL

R-00049157

Docket R-04XXX

Volume 2

Philadelphia Gas Works

DOCUMENT FOLDER

Before The

Pennsylvania Public Utility Commission

Computation of Annual Purchased Gas Costs
For Twelve Months Ending August 31, 2005

66 Pa.C.S. § 1307(f)

Information Submitted Pursuant To:

66 Pa.C.S. §§ 1307(f), 1317, 1318 and
52 Pa. Code § 53.61, et seq.

February 1, 2004

Philadelphia Gas Works 1307f - 2004 Prefiling

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Docket No. R-04XXX
Item 53.64 (c)(5)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(5) A listing and updating, if necessary, of projections of gas supply and demand provided to the Commission for any purpose—see § 59.67 (relating to formats). In addition, provide an accounting of the difference between reported gas supply available and gas supply deliverable—including storage—from the utility to its customers under various circumstances and time periods.

Response:

Please see the attached document. PGW's next Annual Resource Planning Report (Forms 1 and 2) is due for submission to the Commission on March 1, 2004 and no updated Annual Resource Planning Report is available or required at this time.

ANNUAL RESOURCE PLANNING REPORT

Philadelphia Gas Works

Philadelphia, Pennsylvania

March 2003

Forms 1 & 2

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Philadelphia Gas Works
800 West Montgomery Avenue
Philadelphia, Pennsylvania 19122

ANNUAL RESOURCE PLANNING REPORT
MARCH 2003

Forms 1 & 2

Information Submitted in Compliance with and Pursuant to Title 52 Pennsylvania Code Section 59.81

PHILADELPHIA GAS WORKS

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Section 59.81: **General**

Pursuant to Section 59.81 (a), each major jurisdictional gas utility must file an annual resource planning report (ARPR) on or before June 1, 1996 and June 1 of each succeeding year, except Form 1A/2A which filing date is March 1. One (1) original and seven (7) copies of the report must be submitted to:

Secretary
Pennsylvania Public Utility Commission
P.O. Box 3265
Harrisburg, PA 17105-3265

One copy should be submitted unbound for ease of duplication.

One courtesy copy should also be submitted to:

Pennsylvania Public Utility Commission
Conservation, Economics and Energy Planning
P.O. Box 3265
Harrisburg, PA 17105-3265
Attn. Calvin Birge

Also submit one (1) copy to the following:

Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1921

Office of Small Business Advocate
Suite 1102, Commerce Building
300 N. Second Street
Harrisburg, PA 17101

Be sure to indicate the name and telephone number of at least one individual at the company who is familiar with the filing and will be available to answer any questions the Commission staff may have. You may also wish to list those individuals who are directly involved in the preparation of the various document components.

Information contained in annual resource planning reports must be utility-specific. The report should follow an outline similar to that which is contained herein, with narrative accompanying the required data. Forms may be modified to accommodate wide columns of numbers and enhance readability, but the general format should be used to maintain consistency.

This information is not generally considered confidential. Utilities are obligated to provide complete information. However, we will treat as confidential those portions of the report designated by the utility as proprietary. If a utility's proprietary claim is challenged, the Commission will direct the utility to file a petition for protective order pursuant to 52 PA Code 5.423.

All questions concerning the reporting requirements for Forms IRP Gas 1A through 9 should be addressed to Pennsylvania Public Utility Commission Bureau of Conservation, Economics and Energy Planning.

Response: An original, seven (7) copies, and one unbound copy of Forms 1A, 1B, 2A, 2b, and 2C along with a general discussion of the methodologies, data sources, and assumptions are being submitted to meet the requirements of the March 1 filing.

All questions concerning the ARPR should be directed to Mr. Kenneth Dybalski, Manager - Gas Planning at (215) 684-6713. The following individual will be available to answer questions concerning each section:

Ms. Maria Hogan, Administrator – Gas Planning at (215) 684-6618.

Section 59.81 **Forms IRP-Gas 1A, and 1B – Annual and Peak Day Demand**

The load growth projections shall reflect the effects of price elasticity, market induced conservation, building and appliance efficiency standards, and the effects of the utility's existing and planned conservation and load management activities.

Response: *Please see the attached documentation and forms.*

FORM-IRP-GAS-1A: ANNUAL GAS REQUIREMENTS
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(VOLUMES IN MMcf)

	Historical Data		Current Year	Three Year Forecast [2]		
Index Year	-2	-1	0	1	2	3
Actual Year	2000-2001 [1]	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006
Firm Requirements						
Retail Residential	44,865	35,591	47,192	46,193	46,018	45,947
Retail Commercial	12,550	10,369	12,862	13,162	13,311	13,409
Retail Industrial	1,476	1,098	1,316	1,690	1,854	2,008
Electric Power Generation						
Exchanges with Other Utilities						-
Unaccounted For Gas	2,478	1,416	2,644	2,384	2,390	2,397
Company Use	107	126	127	93	93	93
Other	-	-	-	-	-	-
Subtotal Firm	61,476	48,599	64,141	63,522	63,666	63,855
Interruptible Requirements:						
Retail	5,865	6,315	7,678	6,740	5,943	5,402
Electric Power Generation	123	114	141	99	78	58
Company's Own Plant	290	258	427	293	391	330
Unaccounted For Gas	245	185	376	392	165	180
Subtotal Interruptible	6,522	6,872	8,622	7,523	6,577	5,971
SUBTOTAL FIRM AND INTERRUPTIBLE	67,999	55,471	72,763	71,045	70,243	69,825
Transportation						
Firm Residential						
Firm Commercial						
Firm Industrial						
Interruptible Residential						
Interruptible Commercial	-	-	-	-	-	-
Interruptible Industrial [3]	822	2,416	3,682	4,245	5,323	5,855
Other - Non-Utility Power Producers	7,011	9,903	9,204	9,101	9,101	9,101
Subtotal Transportation	7,833	12,318	12,886	13,346	14,424	14,956
TOTAL GAS REQUIREMENTS	75,832	67,790	85,649	84,391	84,668	84,781
Increase (Decrease)	na	(8,042)	17,859	(1,258)	277	114
Percent Change (%)	na	-10.61%	26.34%	-1.47%	0.33%	0.13%

[1] Revised
[2] Deregulation is assumed only to affect interruptible customers and not firm customers.
[3] For the forecasted years, Commercial and Industrial transportation are combined

FORM-IRP-GAS-1B:PEAK DAY REQUIREMENTS [3]
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(VOLUMES IN MMcf)

	Historical Data		Current Year	Three Year Forecast [2]		
Index Year	-2	-1	0	1	2	3
Actual Year	2000-2001 [1]	2001-2002	2002-2003	2003-2004	2004-2005	2005-2006
Firm Requirements						
Retail Residential	375 7	319.2	435.8	513	509	508
Retail Commercial	105 1	93.0	118.8	146	147	148
Retail Industrial	12 4	9.8	12.2	19	21	22
Electric Power Generation	0 0	0.0	0.0	0	0	0
Exchanges with Other Utilities	0 0	0.0	0.0	0	0	0
Unaccounted For Gas	20 7	12.7	21.6	26	26	27
Company Use	0 9	1.1	1.2	1	1	1
Other	0	0	0.0	0	0	0
Subtotal Firm	514 8	435.8	589.5	705	704	706
Interruptible Requirements.						
Retail	4 2	22.8	25.1	0	0	0
Electric Power Generation	0 0	0.0	0.0	0	0	0
Company's Own Plant	1 1	0.6	1.5	3	3	3
Unaccounted For Gas	0 0	0.0	0.0	0	0	0
Subtotal Interruptible	5 3	23.5	26.6	3	3	3
SUBTOTAL FIRM AND INTERRUPTIBLE	520 1	459.3	616.1	708	708	709
Transportation						
Firm Residential	0 0	0 0	0.0	0	0	0
Firm Commercial	0 0	0 0	0.0	0	0	0
Firm Industrial	0 0	0 0	0 0	0	0	0
Interruptible Residential	0 0	0 0	0 0	0	0	0
Interruptible Commercial	0 0	0 0	0 0	0	0	0
Interruptible Industrial	0 0	0 3	0 8	0	0	0
Other - Non-Utility Power Producers	20 1	36 9	41 8	0	0	0
Subtotal Transportation	20 1	37 2	42.6	0	0	0
TOTAL GAS REQUIREMENTS	540 2	496 5	658.8	708	708	709
Increase (Decrease)	na	(44)	162	49	(0)	1
Percent Change (%)	na	-8 10%	32.69%	7.44%	-0.02%	0.17%

[1] Revised

[2] Deregulation is assumed only to affect interruptible customers and not firm customers.

[3] Peak Day is forecasted at a 2 degree temperature

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

PHILADELPHIA GAS WORKS
800 WEST MONTGOMERY AVENUE
PHILADELPHIA, PENNSYLVANIA

Annual Resource Planning Summary Report

Filed: March 2003

Information Submitted in Compliance with and Pursuant to Title 52
Pennsylvania Code Sections 59.81-59.84

PHILADELPHIA GAS WORKS
2003 Annual Resource Planning Summary Report

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Introduction

By Order entered January 11, 1996, the Pennsylvania Public Utility Commission (PUC) adopted final regulations (52 PA Code §§ 59.81 - 59.84) which set forth revised requirements for filing an Annual Resource Planning Report (the Plan). The Plan submitted represents Philadelphia Gas Works' (PGW or the Company) belief that integrated resource planning (IRP) is a workable approach to utility planning.

This plan summary contains historical data and projections for annual, winter and peak day supply to meet projected customer requirements in a least cost manner, while ensuring adequate and reliable service. It is organized into the following 6 sections:

I. PGW's Overall Approach to Integrated Resource Planning

II. Supply Forecasting Methodology and Assumptions

III. Demand Forecasting Methodology and Assumptions

IV Design Day Forecasting Methodology and Assumptions

V. PGW Corporate Modeling System

I. PGW's Overall Approach to Integrated Resource Planning

PGW Optimization Standard for Purchasing and Utilizing Gas Supplies

As reasonably anticipated, PGW intends meeting its contractual obligations to supply all of its current customers in its service territory on the coldest day and throughout the season. Projected customer requirements for design day and design winter conditions form the basis for capacity commitments for pipeline supply, storage, and transportation contracting.

Natural gas supplies are purchased under a portfolio approach, intending to secure the lowest overall price, consistent with the primary corporate goals of reliability and security of supply. In addition, consideration is given to maintaining a diversity of sources and types of supply, coupled with contractual and operational flexibility on both a daily and seasonal basis. Short term purchases from spot market sources are utilized to the maximum degree that they are more economical, available, and transportable.

Natural gas supplies are utilized so as to maximize net contributions subject to reliability constraints. Supply contract obligations are honored and prudent Gas Control operational requirements are assumed. Storage contracts are drawn upon so as to always maintain an inventory level sufficient for protection in the event that design temperature conditions should occur in the remaining segment of any winter season. Within the above parameters, priority is given to utilizing the most economical sources of supply first, within the context of preserving the capability of meeting seasonal and annual demands rather than the momentary daily requirements. All facilities and sources of supply, flowing, storage and LNG are available to achieve the intended end; namely, maximizing net contributions subject to reliability constraints.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions

The PGW Gas Supply Policy Committee, representing senior corporate management as well as Gas Planning, Gas Control, Gas Supply, and Regulatory departmental management, approved the aforementioned Optimization Standard for Purchasing and Utilizing Gas Supplies (Section I). All natural gas purchases continue to be made in accordance with this standard. Projected sales, revenues and natural gas expenses in this report result from this agreement, particularly in the areas of inventory valuation, priorities of gas selection and interruptible supply availability.

Incorporated into our projections are additional implementation steps involved with developing a cohesive gas supply/demand strategy for the near term and the longer range. These include developing a cost relationship comparison for current resources and a review of current contract terms and alternatives for continuing, extending, modifying or eliminating contracts.
In order to achieve this while maintaining a balance between economics and security of supply, the company uses a portfolio strategy approach. This approach incorporates a menu driven selection of services which allows the company to choose only those specific services necessary to meet its requirements. This is achieved by first securing transportation capacity rights. Then sources of supply are contracted to cover the firm transport rights taking into consideration differing seasonal obligations.

Operating flexibility is sustained by variations in contract stipulations, to permit the system to swing on the most economical gas supplies available while maintaining the ability to supply rapidly fluctuating temperature requirements. Storage facilities are substituted wherever opportunity affords to reduce annual expense for flowing 365 day pipeline service without damage to peak day and peak winter season delivery capability. Direct control of all storage is sought to permit PGW to minimize winter costs by injecting lower priced summer purchases and to cycle storage to balance daily take fluctuations to avoid overrun/balancing charges.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

PGW's supply strategy incorporates maintaining full current winter day deliverabilty with regard to transportation capacity but to convert, where possible, to storage rather than winter flowing contracts to enhance financial and operational flexibility. A variety of long term supply contracts are necessary to support pipeline transportation capacity because reliance upon best effort spot suppliers to fill wintertime capacity required to meet firm customers' demands has proven to be an unreliable alternative. As a result, longer-term contracts are utilized to support firm transportation capacity. To accomplish this end, the Company purchases winter supply contracts with daily deliverabilty equal to approximately 58% of the contractual daily transportation entitlements on its two interstate pipelines with direct connections to PGW's service territory. Additionally, these supply contracts match the contractual entitlements of the two pipelines by sourcing supply in a manner consistent with the pipeline's upstream contractual requirements. In this way, PGW not only helps ensure the security of supply by sourcing the gas from geographically diverse supply regions but this diversity also allows PGW to take advantage of the pricing basis differential inherent in these supply locations.

These contracts all contain the ability to fix the price for upcoming months as well as to allow the pricing to default to an agreed upon market index when there is no market advantage in fixing a price before the month begins. PGW uses this fixed price option in conjunction with its Gas Cost Rate (GCR) filing (GCR filing includes pricing based upon the NYMEX and Standard and Poors' "DRI Price Forecast") by always attempting to buy under the GCR forecasted prices. Through the matching of the duration supply contracts to a seasonal demand, such as the winter operating season, the firm ratepayers benefit from not paying demand charges year-round.

A second component of PGW's supply portfolio, or a volume equal to 32% of pipeline capacity, is purchased gas based on a first-of-the-month index pricing methodology, with contracts that allow for daily change in volumetric take. This allows the Company to effectively shut-off higher priced supply, replacing such supply with daily cheaper spot priced gases. Under assumed normal winter conditions, PGW utilizes certain storage fields (ANR, Eminences and Washington), in a manner similar to third party supply.

II. Supply Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

Specifically, these storage contracts do not contain bundled transportation to the PGW city gate. Therefore, storages must flow within PGW's contractual upstream capacity rights on TETCO and TGPL. Typical daily delivery from these fields utilizes approximately 10% of the daily TETCO and TGPL capacity rights to the Philadelphia city gates. These storage fields also act as a physical fixed price counter to winter price conditions since the WACOG usually reflects a winter/summer pricing differential. PGW's summer purchasing strategy also incorporates a portfolio approach to the purchase of system supply and storage refill. The GCR filing is again used as a yardstick in purchasing supply for both system supply and storage refill. PGW attempts to always purchase a portion of its supply needs below the projected GCR cost estimate with a portion of the portfolio purchased at default, first-of-the-month pricing. These first of the month pricing option contracts, in most instances, allow PGW to evaluate daily spot prices and provide for a turn-off of first-of-the-month index priced supply in favor of the purchase of more advantageous daily spot purchases.

Operating conditions permitting, the Company enters into the FERC approved capacity release market to offset demand charges it pays for its firm transportation and/or the incremental off-systems sales market when it is economically advantageous for the firm ratepayer. In both instances, these opportunities are sought only when firm customer needs are satisfied. Additionally, PGW's bundled storages and LNG can be utilized as a substitute for higher price gas supply based on market pricing conditions and the results of PGW's weekly status report. Effectively, the Gas Supply Group is at all times studying the market for any economic advantage it can bring to the firm ratepayer.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions

PGW uses a combination of four basic methods to develop demand projections. They are:

1) Customer Survey - Information as gathered by PGW's Marketing Department and used for annual projections by month and year.
2) Relative End Use -- Projections via Marketing methods of customer load sizing by appliance type, maximum input, maximum summer and winter full load hour (FLH) calculations which are used to develop yearly and monthly demand requirements.
3) Historical Data -- data showing long-term demand trends, conservation and utilization patterns by the various classes of customers -- Residential, Commercial, Industrial and Interruptible.
4) Judgement -- Experienced opinion as applied to the evaluation of the combination of all data to develop the basic demand requirements.

Customer Demand

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, consideration is given to projecting current customer usage, augmented by significant gains or losses in each of 43 homogeneous groups for the period being projected. The Gas Planning Department attempts to determine, for each customer class, the level of demand reliable to experienced temperature and the component of demand that is apparently 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 an insight into 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, reveals the temperature sensitive load requirements for each class of customer.

This usage primarily reflects space heating, but also includes such other temperature sensitive needs as water heating attributable to colder ground water inlet temperatures and similar process variations, as well as supplementary range 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.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

In addition, consideration must be 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 spring. These usage patterns taken in conjunction with anticipated customer counts and appropriate temperature patterns form the basis of determining class and total system demands. Due to the inconsistencies of weather and weather forecasting techniques, 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 4555 degree-days annually distributed in a stylized pattern preserving the monthly range of colder to warmer daily temperatures experienced in the January to May period and warmer to colder daily temperatures in the September to December period.

The term "degree days" quantifies the number of degrees of temperature below a base level of 65 degrees Fahrenheit as a tool to measure space heating requirements, i.e., on a day experiencing an average temperature of 40 degrees F. there would be counted 25 degree days. The annual 4555 degree days, which compose the PGW normal monthly temperature patterns, form the basis of the calculation of the temperature sensitive component of demand. 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 statement of total customer requirements identified as sendout. It should be noted that there is a difference between sendout volume and sales volume. Sendout represents those volumes that left the plant initially to supply customers' requirements, while sales are those volumes reported on customer meters. The variation between sendout and sales is that portion which is lost and unaccounted for in the PGW distribution system. In addition, they differ on a monthly basis in the distribution pattern. For the convenience of distributing meter reading and billing efforts uniformly over the available number of working days in a month, the majority of PGW customers are divided into 20 individual groups or cycles, containing residential, commercial and industrial accounts within a specific geographic area.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

When these cycle customers are billed each month, they reflect meter reading usage not for the calendar month being billed, but for the number of days and temperature pattern of degree-days experienced during their specific interval between readings.
For example, assume the month of January contained 900 degree-days. The customers in cycle 10 being billed for the month of January might have had meter readings taken on December 15 and again on January 17. Sales billed and reported in company records for these customers would have reflected the number of days and degree days between these reading dates rather than the 900 degree days of the month. Similarly, cycle 1 customers that might have had meter readings taken on December 1 and January 2 would reflect principally the December temperature experience, while cycle 20 customers, with meter readings taken possibly December 28 and January 29, would reflect principally the January temperature experience.

An average of the 20 cycles (Average Cycle Degree-Days) is used as the temperature pattern upon which to project the potential volume of sales in the estimation period. Both projections of sales and sendouts represent the full potential demand for that period from both firm and interruptible customers.

Methodology Used to Develop Monthly Estimates

A trial domestic factor is developed by class of customer from sales reported for the previous year's summer months. This average factor is then utilized in the sendout formula with the customer counts for the months of July, August and September. A comparison between what the formula calculates and the actual experienced for those three months is ascertained and the trial domestic factors are finalized to replicate the total sendout experienced. The finalized domestic factors (DOMs) are then utilized in conjunction with the actual sales and customer counts for the months of December, January and February to determine the average Mcf per degree day for each of the individual months for the remaining temperature sensitive load. The results are weighted by degree-days to give an average value which is utilized as a trial value for the heating factor.

III. Demand Forecasting Methodology and Assumptions
Basic Assumptions (Continued)

The finalized domestic factor and the trial heating factor developed, as such, are then applied in the sendout calculations, together with customer counts for the months of December, January and February, the peak winter cold period, to project an estimated sendout for each of these months. The projected sendout is then compared with the actual sendout experienced. Any variation between the projected and actual is adjusted to force the replication of the actual sendout experience, thus resulting in the determination of a finalized heating factor.

To project the number of customers for each individual rate class, the following categories of customers are reviewed and accumulated individually: current customers are ascertained from the number of billings data available from sales and revenue actually experienced immediately prior to the commencement of a budget run. Declines are projected for anticipated losses to electric and other fuels or demolitions and from transfers to other rates. Direct transfers from a non-heating to a heating account, as a result of a current customer's conversion to gas heat, moves the domestic load to the new category. Projected additional customers are developed within the Marketing Department, where staff dealing with individual classes of customers and having the most direct knowledge of conditions within their sphere, project annual load additions which are translated into count based upon typical customer usage for that individual customer class. The approximate month of turn-on is also developed to permit reflection of the effective portion of the load addition within the fiscal period under study. Interruptible class customers, as well as other large special accounts, are detailed individually incorporating expected gains and losses as direct contact has indicated.

The base revenue projections for both firm and interruptible customer groups are derived as the product of the projected sales volumes and the present tariff rate for each individual customer class within each group. The GCR revenue projections are derived as the product of the GCR factor and the projected sales volumes to the non-interruptible customers.

III. *Demand Forecasting Methodology and Assumptions*
Basic Assumptions (Continued)

Finally, incremental Marketing efforts are concentrated on Air Conditioning and Co-generation opportunities. Rate design has been implemented fostering off-peak increase in utilization of current supply resources in an air conditioning discount, an interruptible Co-generation Rate and a Natural Gas Vehicle (NGV) Service. It is intended to limit on-peak expansion to acceptable interruptible availability of current resources rather than allowing the creation of new peak demands, prospective load management.

IV. Design Day Forecasting Methodology and Assumptions

Each year, a six year estimate of Design Day requirements anticipated under design day operating conditions is prepared to ensure that adequate resources are under contract and to further ensure that PGW can fulfil its utility obligation to its firm customer requirements on the design day and design hour.

The projected demands for design day is developed utilizing previous winter period data, for all weekdays where the temperature average for the day is 32 degrees Fahrenheit or below. The total sendout for these days as recorded under actual conditions is reduced to base sendout by removal of the interruptible load. A computer generated linear regression procedure is utilized to develop a calculated sendout versus the actual sendout from which the necessary constants (factors) required to have the calculated sendout match, within a reasonable percent of error to the actual sendout are developed. The process is repeated in a quadratic regression and a cubic regression procedure. This approach produces a curvilinear regression method, the results of which are analyzed by statistical significance testing and the best-fit curve is selected for use in developing the design day sendouts. The factors derived from the curve selected are used to calculate current load requirements for a 0 degrees F day and a -5 degrees F hour. PGW's Marketing Department's load projections for present and future years are then applied to these requirements to develop design day and design hour present and future load requirements. This is achieved by the addition of the projected marketing load growth expectations on an annual basis (by day) to the derived base-year design day requirements.

V. PGW Corporate Modeling System

General Description

The corporate model system is a tool used by PGW management to project sales, revenues and expenses, as well as to examine key planning strategies and evaluate their effects on company operations. The system provides the ability to determine the results of alternate plans and scenarios, while at the same time allowing for responses to "what if" type situations quantifying revenue and expenses. The system is totally interactive in that it combines the power of the computer with the experience of management to develop both short and long range projections based upon experienced historical data for sales and sendout volumes, raw material expenses and sale revenues. The corporate model system is composed of five separate models. Each model operates independently, but requires substantial external data inputs as well as data output results from one or more of the other models in the system.

Gas Demand Model

The gas demand model is used to forecast total requirements for gas based upon current customer usage experience with adjustments for projected gains and losses. Input data includes domestic and space heating usage factors, customer counts by rate classifications, temperature patterns and results in projections of sales and sendout volumes. Detail and summary reports include average usage per customer and demands by rate classification. This data is transferred to the supply model.

Gas Supply Model

The supply model is used to dispatch the various supply sources in accordance with contract availability limitations. It develops the necessary balance between supply and demand, which reflects plant fuel and storage re-injection requirements as well as customer demands, by identifying the availability of interruptible load balancing sales. Detail and summary reports include daily and monthly load requirements, the volumes taken from each source by pipeline contract, storage balances, supplemental fuel requirements, etc. Data is transferred to both the cost model and the revenue model downstream.

V. PGW Corporate Modeling System (Continued)

Gas Cost Model

The gas cost model is used to determine natural gas and other raw material costs dispatched. The model tracks the various cost components of each contract - the demand, capacity, commodity, injection and withdrawal charges - providing monthly and annual details and summary information, including inventory valuations and expenses for supplemental LNG supplies. It transfers these expenses to the Gas Cost Rate Model.

Gas Cost Rate Model

The gas cost rate model is used to develop a base fuel charge and a fuel adjustment factor known as the Gas Cost Rate (GCR). It ascribes responsibility for the raw material costs, to firm and interruptible classes in accordance with PGW's tariff requirements, assigning cost on an as-used basis to customer classes applicable to such charges, and compensates for natural gas refunds and previous over or under billing of fuel expenses. Detail summary reports include specifics of raw material adjustment, statements of reconciliation, and determination of applicable sales and expenses, transferring its results to the revenue model.

Revenue Model

The revenue model is used to project billed revenue by rate classification in accordance with PGW's rate tariffs. It prepares both base non-fuel and base fuel revenue statements, GCR revenues, senior citizen discounts, and cycle and budget billing information, all detailed by rate classification. The detail and summary reports provided by this model are directed to the accounting and financial departments for inclusion in various financial reviews.

Summary

The corporate model system allows PGW management to effectively address supply/demand balancing, supply facilities planning, projected sales, cost, revenues, and sendout volumes in a timely manner. Results assist in the development of PGW's annual Operating Budget.

V. PGW Corporate Modeling System (Continued)

The model allows the evaluation of future winter requirements on both normal and design temperature patterns and the extrapolation of current years based upon the experience to date and an assumption of temperatures anticipated for the remaining period of the year, this latter acting as a guide for both financial cash flow planning and winter operations.

Section 59.81

Forms IRP-Gas 2A, 2B and 2C - Annual and Peak Day Energy Resources, Transmission and Storage Contracts

The forecast of energy sources shall indicate sources of all presently available and new supplies which the utility estimates will become available, displayed by component parts.

Response:

Please see the attached documentation and forms.

FORM-IRP-GAS-2A: NATURAL GAS SUPPLY
TABLE 1: ANNUAL/PEAK SUPPLY
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(Volumes in MMcf)

	Historical Data				Current Year		Three Year Forecast [2]					
Index Year	-2		-1		0		1		2		3	
Actual Year	2000-2001		2001-2002		2002-2003		2003-2004		2004-2005		2005-2006	
	Annual	Peak [1]	Annual	Peak [1]	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
Gas Supply for Sales Service												
TETCO			-	-	-	-	-	-	-	-	-	-
TRANSCO	9,521	52.7	5,401	1.0	17,035	55.2	12,301	53.4	19,379	53	19,378	53
Spot Purchases	54,431	219.4	53,905	189.8	56,710	181.9	56,528	242.7	51,322	254	50,608	222
Storage Withdrawals	17,233	125.1	14,817	257.3	17,041	208.1	13,189	173.6	11,511	162	10,874	176
LNG Withdrawal	3,612	123.0	1,242	11.2	3,432	170.9	2,237	238	2,179	238	3,471	257
Company Production	-	-	-	-	-	-	-	-	-	-	-	-
LNG Purchases	-	-	-	-	127	-	-	-	-	-	-	-
Exchanges with other LDCs	-	-	-	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-	-	-	-
Total Gas Supply	84,797	520.1	75,364	459.3	94,344	616.1	84,255	708	84,392	708	84,330	709
Total Transportation Services	7,833	20.1	12,318	37.2	12,886	42.6	13,346	-	14,424	-	14,956	-
TOTAL GAS SUPPLY AND TRANSPORTATION SERVICE	92,629	540.2	87,683	496.5	107,230	658.8	97,601	708	98,816	708	99,286	709
Deductions												
Underground Storage Injections & Fuels	12,855	-	16,425	-	18,032	-	10,821	-	11,822	-	11,741	-
LNG Liquefactions & Fuels	3,109	-	1,666	-	3,551	-	2,389	-	2,326	-	2,763	-
Sales to other LDC's	834	-	1,802	-	-	-	-	-	-	-	-	-
Total Deductions	16,798	-	19,893	-	21,582	-	13,210	-	14,149	-	14,505	-
NET GAS SUPPLY	75,832	540.2	67,790	496.5	85,648	658.8	84,391	708	84,668	708	84,782	709

[1] Revised

[2] Peak Day is forecasted at a 2 degree temperature

FORM-IRP-GAS-2B: NATURAL GAS TRANSPORTATION
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(volumes in MMcf)

	Historical Data				Current Year		Three Year Forecast [2]					
Index Year	-2		-1		0		1		2		3	
Actual year	2000-2001 [1]		2001-2002		2002-2003		2003-2004		2004-2005		2005-2006	
City Gate Transportation Contracts:	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
Transcontinental Transmission Corp.	3,723	43	3,723	57	3,723	53	3,723	52	3,723	52	3,723	52
Texas Eastern Transmission Corp.	2,570	30	2,570	41	2,570	39	2,570	43	2,570	43	2,570	43
Texas Eastern Transmission Corp.	2,390	13	2,390	19	2,390	20	2,390	20	2,390	20	2,390	20
Transcontinental Transmission Corp.	453	5	453	5	453	5	453	4	453	4	453	4
Total	9,137	91	9,137	122	9,137	117	9,137	120	9,137	120	9,137	120
Upstream Transportation Contracts:												
Transcontinental Transmission Corp.	58,546	158	58,546	158	58,546	159	58,546	160	58,546	160	58,546	160
Texas Eastern Transmission Corp.	26,578	72	26,578	73	26,578	72	26,578	73	26,578	73	26,578	73
Texas Eastern Transmission Corp.	8,442	23	8,442	23	8,442	23	8,442	23	8,442	23	8,442	23
Texas Eastern Transmission Corp.	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17
Texas Eastern Transmission Corp.	2,359	3	2,359	17	2,359	17	2,359	17	2,359	17	2,359	17
Transcontinental Transmission Corp.	172	2	172	2	172	2	172	2	172	2	172	2
Total	98,456	274	98,456	290	98,456	290	98,456	293	98,456	293	98,456	293
Storage-Related Transportation Contracts:												
Dominion Transmission Inc.	9,110	25	9,110	25	9,110	25	9,110	22	9,110	22	9,110	22
Dominion Transmission Inc.	2,760	3	2,760	8	2,760	8	2,760	7	2,760	7	2,760	7
Equitrans	1,911	5	1,911	5	1,911	5	1,911	5	-	-	-	-
Total	13,782	33	13,782	37	13,782	37	13,782	33	11,870	28	11,870	28

(1) Revised

(2) Peak Day is forecasted at a 2 degree temperature.

FORM-IRP-GAS-2C: NATURAL GAS STORAGE [1]
REPORTING UTILITY: PHILADELPHIA GAS WORKS
(volumes in MMcf)

	Historical Data				Current Year		Three Year Forecast					
Index Year	-2		-1		0		1		2		3	
Actual year	2001		2002		2003		2004		2005		2006	
	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak	Annual	Peak
Transcontinental Transmission Corp	3,723	43	3,723	57	3,723	53	3,723	52	3,723	52	3,723	52
Dominion Transmission Inc	3,481	28	3,481	32	3,481	32	3,481	28	3,481	28	3,481	28
Transcontinental Transmission Corp.	3,086	22	3,086	28	3,086	20	3,086	36	3,086	36	3,086	36
Texas Eastern Transmission Corp.	2,467	30	2,467	41	2,467	39	2,467	43	2,467	43	2,467	43
Texas Eastern Transmission Corp.	2,219	13	2,219	19	2,219	20	2,219	20	2,219	20	2,219	20
ANR	1,824	12	1,824	12	1,824	12	-	-	-	-	-	-
Transcontinental Transmission Corp.	165	-	802	34	802	13	802	80	802	80	802	80
Equitrans	507	5	507	5	507	5	507	5	-	-	-	-
Transcontinental Transmission Corp.	453	5	453	5	453	5	453	4	453	4	453	4
Total	17,925	158	18,562	233	18,562	199	16,738	269	16,231	264	16,231	264

[1] Rank contracts in order of magnitude for the current year, noting the transportation provided and termination date for each contract reported
Reporting should proceed along rank ordering until 75% of total is accounted for, or until ten contracts have been listed, whichever occurs first.

Conversions at 1030 Btu

	Contract Expiration Date [2]
Transcontinental Transmission Corp.	3/31/13
Dominion Transmission Inc.	3/31/06
Transcontinental Transmission Corp.	Evergreen
Texas Eastern Transmission Corp.	4/30/12
Texas Eastern Transmission Corp.	4/30/12
ANR	3/31/03
Transcontinental Transmission Corp.	10/31/13
Equitrans	3/31/04
Transcontinental Transmission Corp	4/15/04

[2] For purposes of this report, all contracts due to expire, except ANR and Equitrans, are assumed renewed for the forecast years.

Docket No. R-04XXX

Item 53.64 (c)(6)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing, of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) as utility seeking recovery of purchased as costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

53.64(c)(6) Each Section 1307 (f) utility shall file with the Commission a statement of its current fuel procurement practices, detailed information concerning, the staffing and expertise of its fuel procurement personnel, a discussion of its methodology for obtaining a least cost and reliable source of as supply, including a discussion of any methodologies, assumptions, models or rules of thumb employed in selecting its gas supply, transportation and storage mix, its loss prevention strategy in the event of fraud, nonperformance or interruption of performance, its participation in capacity release and reallocation programs, the impact, if any, upon least cost fuel procurement by constraints imposed by local transportation end users, interruptible service, balancing, storage and dispatching, options, and its strategy for improving its fuel procurement practices in the future and timetable for implementing these changes.

Response:

I. Current Strategy

PGW's current strategy for meeting, the system's supply requirements is to use a portfolio approach in both contract structures and pricing. The Company's supply portfolio is split into three distinct categories. First, the Company enters into winter-only supply contracts. These winter-only supply arrangements provide gas supply that fills approximately sixty-four percent (64%) of PGW's daily firm transportation entitlements on both Duke Energy Gas Transmission and Williams Gas Pipeline.

Item 53.64(c)(6) continued

The Duke Energy and Williams pipelines represent the only interstate pipeline facilities with physical connections to the PGW service territory. These supply contracts also recognize pipeline receipt and delivery rights. By sourcing supply in this manner, PGW not only ensures security of supply from the pipelines, but also can take advantage of varying basis differentiated pricing in the market. These contracts all contain the ability to set the price for upcoming months, or to have the pricing, default to an agreed upon market index. Second, an additional thirty-two percent (32 %) of PGW's gas supply portfolio is purchased on "first of the month index" priced contracts that allow for daily changes in volume. The operational flexibility of these contracts allows the company to increase or decrease gas supply to meet variations in sendout requirements at a known price. Third the company utilizes two (2) pipeline storage services, as an additional source of supply. These storage services do not contain bundled transportation and therefore are moved to the city gates within PGW's firm interstate pipeline capacity. These services represent four percent (4 %) of supply at a fixed price.

Additionally, PGW utilizes bundled storage and LNG to meet operational requirements and to accomplish other cost saving initiatives. Specifically, once design winter sendout requirements are ensured of being met, the company may utilize bundled storage and LNG inventories to displace higher priced supply based on then current market conditions. PGW's also uses a portfolio approach to address system supply and storage refill in the traditional non-peak season. The Gas Supply area uses the GCR filing as a template in an attempt to purchase gas volumes for both system supply and storage refill below the projected cost, when possible. However, some proportion of the supply will always be subject to spot market pricing either daily or monthly due to the constant need to purchase gas to meet sendout variations that are inherent in a residential firm heating load. PGW seeks to recoup demand charges for its firm transportation through the FERC approved capacity release mechanisms.

The Company also enters into the incremental off systems sales market to generate additional revenue when it is economically advantageous to do so. At all times the Company is studying, the market for any, economic advantage that can be derived in support of the firm ratepayer.

Item 53.64(c)(6) continued

II. Overview of Gas Supply Section

The Gas Supply Section of Gas Management is comprised of four departments: Gas Supply, Gas Transportation, Gas Accounting and Gas Control. The Gas Supply Section is responsible for ensuring that there is an adequate supply of natural gas available at all times to meet the requirements of PGW's over 500,000 firm customers. The Gas Supply Section accomplishes this through continuos interaction with various departments within PGW.

The staff of the Gas Supply Section is expected to maintain an in-depth working knowledge of all facets of the natural gas supply markets. The staff members of the four departments are required to maintain a working knowledge of PGW's natural gas contracts and facilities for the purpose of ensuring the safe and efficient operation of the distribution system, in accordance with company procedures, and in compliance with federal, state, and local regulations.

III. Organization and Staffing

Director of Gas Supply: This person has a fifteen-year history in the gas supply area of the company and an eight-year history in gas control. The individual has an MBA and BS degree and an regulatory background, which takes into account the initial stages of FERC Orders 636 and 637 and there effects on sendout and supply portfolio management.

Director of Gas Transportation and Gas Control: This person has a twelve-year history in the supply area and a three-year history in gas control. This individual has a BA as well as having a background in natural gas accounting, allocation and confirmation experience under the first stages of FERC Order 636, and its effect on supply portfolio management.

These two individuals interact continuously and provide 24/7 coverage in all situations pertaining to the gas supply portfolio and operation of the natural gas facilities. The following departments report directly to these two individuals Gas Supply, Gas Control, Gas Accounting, and Gas Transportation.

Item 53.64(c)(6) continued

Manager, Gas Accounting this person has over eight years experience in the gas supply area. This individual has a MBA and BS in addition to having an extensive background in the area of gas accounting. Reporting to this individual is the gas accountants and contract administrator.

Manager, Gas Control: This person has over nine years in the supply area, is responsible for the day-today management of the city distribution grid as well as daily confirmation of each day's gas volumes. He supervises the gas control department on a 24/7 basis. The manager has a BS degree and extends duty in the Distribution Department's network analysis area.

Docket No. R-04XXX
Item 53.64 (c)(7)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(7) A list of off-system sales, including transportation, storage, or capacity releases by the utility at less than the weighted average price of gas, or at less than the original contract cost of transportation, storage, or capacity supplied to the utility for its own customers.

Response:

The attached schedules list off system sales and capacity release for the period of January 1, 2003 to December 31, 2003.

Schedule 1 – reflects all off system sales margins for the period January 1, 2003 to December 31, 2003.

Schedule 2 – would reflect any off system sales transactions, which were done at less than the weighted average cost of gas. The schedule is blank because none of the deals match the criteria.

Schedule 3 – illustrates all capacity release deals.

Schedule 4 - would reflect any individual capacity release transactions, which were done at less than the weighted average cost of capacity.

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.

Schedule 1
Item 53.64(C)(7)

Off-System Sales			
MONTH	Total Revenue	Ratepayer Margin	Total Credit To GCR
Jan-03	$100,000	$100,000	$100,000
Feb-03	$0	$0	$0
Mar-03	$853,060	$853,060	$853,060
Apr-03	$0	$0	$0
May-03	$0	$0	$0
Jun-03	$0	$0	$0
Jul-03	$0	$0	$0
Aug-03	$0	$0	$0
Sep-03	$0	$0	$0
Oct-03	$0	$0	$0
Nov-03	$0	$0	$0
Dec-03	$0	$0	$0

Off System Sale Profits Per WACOG Worksheet

No deals were enacted under the weighted average cost of gas.

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.
For the Twelve Months Ending December 31, 2003

Schedule 3
Item 53.64(C)(7)

	Capacity Release		
	Total	Total	Total
	TGPL	TETCO	GCR
MONTH	Credits	Credits	Credits
Jan-03	$0	$0	$0
Feb-03	$0	$0	$0
Mar-03	$0	$0	$0
Apr-03	$60,480	$0	$60,480
May-03	$124,922	$223,405	$348,397
Jun-03	$223,920	$231,046	$454,966
Jul-03	$290,780	$322,427	$613,207
Aug-03	$231,384	$232,523	$463,907
Sep-03	$120,920	$217,762	$338,722
Oct-03	$0	$0	$0
Nov-03	$0	$0	$0
Dec-03	$0	$0	$0

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.

M / YR	PIPELINE	PATH	RECALL STATUS	MONTHLY VOLUME DTH	TOTAL MONTHLY CREDIT	CREDIT DTH	TOTAL GCR CREDIT	REPLACEMENT SHIPPER
January-03	None							
February-03	None							
March-03	None							
April-03	TRANSCO	3-6	N	300,000	$ 60,480.00	$0.2016	300,000	Sequent Energy Marketing
May-03	TRANSCO	3-6	N	620,000	$124,992.00	$0.2016	$124,992.00	Sequent Energy Marketing
	TETCO	WLA - M-3	N	558,000	$117,702.47	$0.2109	$117,702.47	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$117,702.47	$0.2109	$117,702.47	Grays Ferry
June-03	TRANSCO	3-6	N	300,000	$ 51,480.00	$0.1716	$ 51,480.00	Constellation Power
	TRANSCO	3-6	N	300,000	$ 51,480.00	$0.1716	$ 51,480.00	Constellation Power
	TRANSCO	3-6	N	600,000	$ 120,960.00	$0.2016	$120,960.00	Sequent Energy Marketing
	TETCO	WLA - M-3	N	540,000	$108,128.20	$0.2002	$108,128.20	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$108,128.20	$0.2002	$108,128.20	Grays Ferry

Philadelphia Gas Works
Pennsylvania Public Utilities Commission
52 Pa. Code §53.61, et seq.

M / YR	PIPELINE	PATH	RECALL STATUS	MONTHLY VOLUME DTH	TOTAL MONTHLY CREDIT	CREDIT DTH	TOTAL GCR CREDIT	REPLACEMENT SHIPPER
July-03	TRANSCO	3-6	N	310,000	$ 53,196.00	$0.1716	$ 53,196.00	Constellation Power
	TRANSCO	3-6	N	310,000	$ 53,196.00	$0.1716	$ 53,196.00	Constellation Power
	TRANSCO	3-6	N	310,000	$ 59,396.00	$0.1916	$ 59,396.00	Washington Gas Energy Service
	TRANSCO	3-6	N	620,000	$ 124,992.00	$0.2016	$ 124,992.00	Sequent Energy Marketing
	TETCO	WLA - M-3	N	558,000	$161,213.40	$0.2889	$161,213.40	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$161,213.40	$0.2889	$161,213.40	Grays Ferry
August-03	TRANSCO	3-6	N	310,000	$ 53,196.00	$0.1716	$ 53,196.00	Constellation Power
	TRANSCO	3-6	N	310,000	$ 53,196.00	$0.1716	$ 53,196.00	Constellation Power
	TRANSCO	3-6	N	620,000	$ 124,992.00	$0.2016	$ 124,992.00	Sequent Energy Marketing
	TETCO	WLA - M-3	N	558,000	$11,580.58	$0.0208	$11,580.58	Grays Ferry
	TETCO	WLA - M-3	N	558,000	$11,580.58	$0.0208	$11,580.58	Grays Ferry
September-03	TRANSCO	3-6	N	600,000	$120,960.00	0.2016	$120,960.00	Sequent Energy Marketing
	TETCO	WLA - M-3	N	540,000	$108,881.21	$0.2016	$108,881.21	Grays Ferry
	TETCO	WLA - M-3	N	540,000	$108,881.21	$0.2016	$108,881.21	Grays Ferry
October-03	None							
November-03	None							
December-03	None							

Docket No. R-04XXX
Item 53.64 (c)(8)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(8) A list of agreements to transport gas by the utility through its system, for other utilities, pipelines or jurisdictional customers including the quantity and price of the transportation.

Response:

Please see the attached list of gas transportation agreements for PGW's jurisdictional customers. PGW has no transportation agreements with other utilities or pipeline customers.

Transportation Contracts

2003

Contract #	Maximum Company Obligation Dth/D	Rate
1	1,464	/1
2	60,000	/1
3	250	/1
4	10,000	/1
5	12,000	/1
6	50,000	/1
7	50,000	/1
8	750	/1
9	750	/1
10	706	/1
11	312	/1
12	1,584	/1
13	400	/1
14	305	/1
15	141	/1

Notes:

/1 PGW believes that due to the small number of customer in this rate class, it would be impossible to publish the individual rates without violating customer confidentiality.

Docket No. R-04XXX
Item 53.64 (c)(9)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(9) A schedule depicting historic monthly end-user transportation through-put by customer. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423 (relating to orders to limit availability of proprietary information).

Response:

Please see the attached schedule depicting the monthly end-user transportation through-put by customer.

The Philadelphia Gas Works
1307(f) - 2003
Jan-2003 - Dec-2003 (dth)

No.	Service	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	GT-IT	25,060	9,237	8,270	15,303	13,093	10,282	11,025	14,476	15,928	14,050	16,210	20,224
2	GTS-F	1,497	10	0	5,898	22,400	15,352	21,995	0	5,238	19,722	41,273	27,574
3	GTS-F	11,168	10,898	11,262	11,485	10,963	10,999	11,592	10,372	9,954	11,941	4,847	12,444
4	GTS-I	0	0	0	0	0	0	0	0	0	0	0	0
5	GTS-F	0	0	0	0	0	0	0	0	0	0	0	0
6	GTS-I	0	0	0	0	0	0	0	0	0	0	0	0
7	GTS-F	1,070,068	895,061	862,788	687,844	672,086	665,586	791,444	815,093	753,611	654,679	771,421	832,344
8	GT-IT	0	0	0	0	0	0	0	0	0	0	0	0
9	GT-IT	1,007	0	377	0	0	0	0	0	0	0	0	0
10	GT-IT	9,104	16,531	9,012	11,407	12,201	11,666	11,144	11,127	10,901	13,054	14,526	17,061
11	GT-IT	5,346	4,573	4,698	4,116	3,933	3,386	3,334	2,854	3,070	3,637	3,637	4,557
12	GT-IT	6,320	6,543	3,265	11,797	2,978	2,327	1,737	78	181	1,300	790	3,145
13	GT-IT	0	0	0	0	0	0	0	0	0	3,890	4,910	7,910
14	GT-IT	0	0	0	0	0	0	0	0	0	0	0	5,901
15	GT-IT	0	0	0	0	0	0	0	0	0	0	3,178	3,115

Docket No. R-04XXX
Item 53.64 (c)(10)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(10) A schematic system map, locating and identifying by name, the pressure and capacity of all interstate or intrastate transmission pipeline connections, compressor stations, utility transmission or distribution mains 6 inches or larger in size, storage facilities, including maximum daily injection and withdrawal rates, production fields, and each individual supply or transportation customer which represents 5% or more of total system throughput in a month. Each customer or account shall be identified solely by a unique alphanumeric code, the key to which may be provided subject to § 5.423.

Response:

Following the lead of the industry, as well as federal policy guidelines regarding the security of information relating to energy transmission sites, PGW will no longer provide this data to the general public. However, PGW will provide this information to the Commission for its review under a separate cover, and will also provide this information, upon written request, to parties to this proceeding that have legitimate business reasons to view this information.

Docket No. R-04XXX
Item 53.64 (c)(11)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(11) If any rate structure or rate allocation changes are to be proposed, a detailed explanation of each proposal, reasons therefore, number of customers affected, net effect on each customer class, and how the change relates to or is justified by changes in gas costs proposed in the Section 1307(f) tariff filing. Explain how gas supply, transportation and storage capacity costs are allocated to customers which are primarily nonheating, interruptible or transportation customers.

Response:

PGW is not proposing any rate structure or rate allocation changes in the instant proceeding, therefore, no testimony or schedules have been provided in this pre-filing to support such changes.

PGW will provide testimony regarding gas procurement policies, strategies and GCR calculation in its March 1 filing.

Docket No. R-04XXX
Item 53.64 (c)(12)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(12) A schedule depicting the most recent 5-year consecutive 3-day peak data by customer class (or other historic peak day data used for system planning), daily volumetric throughput by customer class (including end-user transportation throughput), gas interruptions and high, low and average temperature during each day.

Response:

Schedule 1 – Three-day peak for FY 98-99 through FY 02-03.

Schedule 2 – Identifies a listing of gas interruptions for FY 98-99 through FY 02-03, their duration and the high, low and average temperatures for each day that the interruption was in effect.

Winter Peak Season	Date	Average Temperature	Hi Temperature	Low Temperature	Total Sendout (mcfs)	Firm Sendout (mcfs)	Cogen Sendout (mcfs)	LBS Sendout (mcfs)	BPS Sendout (mcfs)	GTS Sendout (mcfs)
1998-1999	Jan 4	23	31	13	513,894	475,659	270	12,350	22,455	3,160
1998-1999	Jan 5	23	30	17	541,880	502,667	280	12,946	22,961	3,026
1998-1999	Jan 6	33	37	23	492,533	451,307	280	14,124	22,983	3,839
1999-2000	Jan 26	25	33	15	524,100	481,941	340	17,370	20,518	3,931
1999-2000	Jan 27	16	21	12	629,033	582,621	350	18,791	23,258	4,013
1999-2000	Jan 28	21	25	16	602,336	556,101	355	18,340	23,722	3,818
2000-2001	Dec 24	29	37	21	444,640	421,627	0	19,800	2,550	663
2000-2001	Dec 25	20	26	17	520,086	515,045	0	1,376	2,831	834
2000-2001	Dec 26	25	30	22	486,331	478,958	0	1,673	4,682	1,018
2001-2002	Dec 30	27	33	22	452,320	431,470	0	7,130	13,405	315
2001-2002	Dec 31	27	34	21	459,593	436,440	0	7,835	15,004	314
2001-2002	Jan 1	30	36	25	441,971	419,432	0	7,968	14,100	471
2002-2003	Jan 22	19	27	13	575,641	548,462	13	832	24,118	2,216
2002-2003	Jan 23	16	22	11	616,928	588,420	0	549	25,204	2,755
2002-2003	Jan 24	25	31	19	540,817	512,675	0	672	25,430	2,040

Interruptions (September 1, 1998 through August 31, 2003)

	TEMPERATURE			GAS INTERRUPTIONS					
DATE	HIGH	LOW	AVERAGE	BPS-S	BPS-H	BPS-L	LBS-S	LBS-L	LBS-XL
12/20/00	32	23	26	X	X	X	X	X	X
12/21/00	36	29	32	X	X	X	X	X	X
12/22/00	34	12	21	X	X	X	X	X	X
12/23/00	31	19	25	X	X	X	X	X	X
12/24/00	37	21	29	X	X	X	X	X	X
12/25/00	26	17	20	X	X	X	X	X	X
12/26/00	30	22	25	X	X	X	X	X	X
12/27/00	34	23	29	X	X	X	X	X	X
12/28/00	28	17	22	X	X	X	X	X	X
12/29/00	34	23	28	X	X	X	X	X	X
12/30/00	31	23	26	X	X	X	X	X	X
12/31/00	37	24	29	X	X	X	X	X	X
1/1/01	36	25	30	X	X	X	X	X	X
1/2/01	29	20	24	X	X	X	X	X	X
1/3/01	37	26	30	X	X	X	X	X	X
1/4/01	38	24	31	X	X	X	X	X	X
1/5/01	38	29	32	X	X	X	X	X	X
1/6/01	40	28	34	X	X	X	X	X	X
1/7/01	47	35	39	X	X	X	X	X	X
1/8/01	42	31	37	X	X	X	X	X	X
1/9/01	34	26	30	X	X	X	X	X	X
1/10/01	40	28	34	X	X	X	X	X	X
1/11/01	51	31	41	X	X	X	X	X	X
1/12/01	48	28	35	X	X	X	X	X	X
1/13/01	47	29	37	X	X	X	X	X	X
1/14/01	44	35	40	X	X	X	X	X	X
1/15/01	44	37	39	X	X	X	X	X	X
1/16/01	46	36	40	X	X	X	X	X	X
1/17/01	45	32	38	X	X	X	X	X	X
1/18/01	39	35	37	X	X	X	X	X	X
1/19/01	42	36	39	X	X	X	X	X	X
1/20/01	36	23	31	X	X	X	X	X	X
1/21/01	32	22	27	X	X	X	X	X	X
1/22/01	39	23	29	X	X	X	X	X	X
1/23/01	41	29	34	X	X	X	X	X	X
1/24/01	47	32	38	X	X	X	X	X	X
1/25/01	40	24	31	X	X	X	X	X	X
1/26/01	39	28	33	X	X	X	X	X	X
1/27/01	42	21	37	X	X	X	X	X	X
1/28/01	40	28	34	X	X	X	X	X	X
1/29/01	42	34	37	X	X	X	X	X	X
1/30/01	58	36	47	X	X	X	X	X	X
1/31/01	53	39	44	X	X	X	X	X	X

DATE	TEMPERATURE HIGH	LOW	AVERAGE	GAS INTERRUPTIONS BPS-S	BPS-H	BPS-L	LBS-S	LBS-L	LBS-XL
1/17/03	33	10	21				X	X	X
1/18/03	26	14	20				X	X	X
1/19/03	37	26	29				X	X	X
1/20/03	38	20	27				X	X	X
1/21/03	32	16	23				X	X	X
1/22/03	27	13	19				X	X	X
1/23/03	22	11	16				X	X	X
1/24/03	31	19	25				X	X	X
1/25/03	35	25	30				X	X	X
1/26/03	38	13	29				X	X	X
1/27/03	21	13	16				X	X	X
1/28/03	31	19	27				X	X	X
1/29/03	34	26	31				X	X	X
1/30/03	37	30	33				X	X	X
1/31/03	39	36	37				X	X	X
2/1/03	44	36	39				X	X	X
2/2/03	46	36	40				X	X	X
2/3/03	53	38	44				X	X	X
2/4/03	49	31	41				X	X	X
2/5/03	36	25	30	X	X	X	X	X	X
2/6/03	35	28	31	X	X	X	X	X	X
2/7/03	38	22	30	X	X	X	X	X	X
2/8/03	34	23	27	X	X	X	X	X	X
2/9/03	42	33	36	X	X	X	X	X	X
2/10/03	37	21	33	X	X	X	X	X	X
2/11/03	36	24	30	X	X	X	X	X	X
2/12/03	32	20	25	X	X	X	X	X	X
2/13/03	33	20	25	X	X	X	X	X	X
2/14/03	37	25	32	X	X	X	X	X	X
2/15/03	29	12	23	X	X	X	X	X	X
2/16/03	25	12	16	X	X	X	X	X	X
2/17/03	30	24	27	X	X	X	X	X	X
2/18/03	37	28	32	X	X	X	X	X	X
2/19/03	45	36	38	X	X	X	X	X	X
2/20/03	54	30	40	X	X	X	X	X	X
2/21/03	52	37	41	X	X	X	X	X	X
2/22/03	44	38	40	X	X	X	X	X	X
2/23/03	48	27	35	X	X	X	X	X	X
2/24/03	44	29	36	X	X	X	X	X	X
2/25/03	38	21	27	X	X	X	X	X	X
2/26/03	29	24	26	X	X	X	X	X	X
2/27/03	34	28	31	X	X	X	X	X	X
2/28/03	42	32	36	X	X	X	X	X	X
3/1/03	42	36	39	X	X	X	X	X	X
3/2/03	48	17	38	X	X	X	X	X	X
3/3/03	32	17	22	X	X	X	X	X	X
3/4/03	44	31	39	X	X	X	X	X	X
3/5/03	56	34	47	X	X	X	X	X	X
3/6/03	35	20	28	X	X	X	X	X	X
3/7/03	41	26	32	X	X	X	X	X	X
3/8/03	56	41	47	X	X	X	X	X	X
3/9/03	56	24	37	X	X	X	X	X	X
3/10/03	36	24	29	X	X	X	X	X	X
3/11/03	41	33	36	X	X	X	X	X	X
3/12/03	56	37	46	X	X	X	X	X	X
3/13/03	58	27	41	X	X	X	X	X	X
3/14/03	46	32	37	X	X	X	X	X	X

Note: X-Denotes that service to this rate schedule was interrupted on the specified date.

Docket No. R-04XXX
Item 53.64 (c)(13)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(13) Identification and support for any peak day methodology used to project future gas demands and studies supporting the validity of the methodology.

Response:

Please see the attached Peak Day analysis and discussion. Additionally, in 1997, ICF Kaiser prepared a *Gas Supply Study* on PGW's behalf. The final study is attached as PGW's response to Item 53.64(c)(14). In addition to that study, ICF Kaiser was also asked to review PGW's peak day methodology as a supplemental study. The results of that study are attached. PGW's analysis methodology has not changed since the study was completed.

Peak Day Analysis

PGW performs a peak day analysis on an annual basis to determine its projected sendout requirements during peak conditions. Essentially this process is completed by collecting sendout and average temperature data for all days where the temperature is below 32 degrees Fahrenheit, excluding holidays and weekends. All transportation and interruptible volumes are removed from total sendout to arrive at firm sendout on a daily basis.

Common statistical practices warrant that no less than thirty (30) data points be utilized in the analysis to ensure its integrity. For this analysis, PGW has utilized data from the period Decemmber 1, 2002 through March 31, 2002 which would reflect the most current consumption behaviors of its customers. This period yielded 34 data points where the average temperature was at or below 32 degrees Fahrenheit.

Degree days are calculated by subtracting the average daily temperature from sixty-five (65).

A standard linear regression was performed on the data using the calculated degree-days and the actual firm daily sendout information. Additionally, in order to confirm the accuracy of the analysis, and to smooth the charting of the data, a quadratic and a cubic regression analysis were also completed.

A resulting R^2 (Correlation Coefficient) indicates that there is a 85.11 % correlation between firm sendout and degree-days. Since PGW's General Service rate schedule includes some commercial and industrial process load, the 85% correlation is acceptable. If the commercial and industrial load were removed from the firm sendout, it is expected that the correlation coefficient would be closer to 100% correlation. The multiple regression correlation coefficient, R^2, is a measure of the proportion of variability explained by, or due to the regression (linear relationship) in a sample of paired data. It is a number between zero and one and a value close to zero suggests a poor model.

To verify the level of confidence we can ascribe to the model, we developed the attached Linear Regression Confidence Level Table. Essentially, this table compares the actual versus projected sendout to determine the level of variance expressed as a standard deviation. A standard deviation represents the positive square root of the variance where the variance simply represents the dispersion about the mean. In this analysis the sample standard deviation is 22,417 Mcf.

To determine the level where the relationship between consumption and degree-days is "significant" it is necessary to incorporate Degrees of Freedom and the Student's T Statistic. Degrees of freedom refer to how many cases in the sample are free to vary.

The sample looses one degree of freedom for each estimated parameter. Thus, with a sample of 100 paired values and two estimated parameters (one for the constant and one for the coefficient of "degree days"), there are 100-2=98 degrees of freedom. In this analysis we had 34 data points and there were 33 Degrees of Freedom.

The critical value is the value the Student's T statistic must equal or exceed to conclude that there is a 97.5% chance that the relationship between consumption and degree days is not 0. A Student'' T statistic of 2.00 is required for a sample with 33 degrees of freedom.

The Student's T statistic is the distribution of the (mean/standard deviation) of a sample of normal distributed values with unknown variance. In this case, it is a measure of the likelihood that the estimated coefficient for "degree days" is actually zero. The farther the statistic is from 0, the greater the likelihood that the sample pairs are related. The Student-T distribution varies with the number of independent values (Degrees of Freedom) from which the variance is calculated. For this example, the T-statistic is calculated as SQRT (R2* (degrees of freedom)/(1-R2)) =13.734199. The calculated Student's T statistic of 13.734199 exceeds the critical value of 2.00. Thus, we can conclude that the relationship between consumption and degree-days is "significant" at the 97.5% level.

Finally, based upon the models developed, it can be determined that the company's projected peak day sendout should be set at 789,202 Mcf per day at 0 degrees Fahrenheit. This calculation is performed using the X Coefficient (i.e. slope) multiplied by the number of degree days and adding the Constant (Y Intercept). In this case the calculation was performed at a temperature of 0 degrees Fahrenheit and at 15 degrees Fahrenheit.

Winter 02-03 Data for Daily Temperatures <= 32 Degrees Fahrenheit
W/O Holidays, Weekends

Day	Date	Daily Temp	Degree Days X	X^2	X^3	Actual Firm Sendout (Mcf)	Firm Sendout Per DD (Mcf)	Linear Projected Firm Sendout (Mcf)	Quadratic Projected Firm Sendout (Mcf)	Cubic Projected Firm Sendout (Mcf)
Mon	03/10/03	29	36	1,296	46,656	431,722	11,992	434,154	433,545	435,128
Fri	03/07/03	32	33	1,089	35,937	387,204	11,733	397,425	399,438	397,696
Thu	03/06/03	28	37	1,369	50,653	431,870	11,672	446,397	445,228	446,798
Mon	03/03/03	22	43	1,849	79,507	485,096	11,281	519,856	518,618	515,845
Thu	02/27/03	31	34	1,156	39,304	419,397	12,335	409,668	410,650	410,684
Wed	02/26/03	26	39	1,521	59,319	461,271	11,827	470,883	469,064	469,570
Tue	02/25/03	27	38	1,444	54,872	432,012	11,369	458,640	457,068	458,243
Tue	02/18/03	32	33	1,089	35,937	414,921	12,573	397,425	399,438	397,696
Fri	02/14/03	32	33	1,089	35,937	404,972	12,272	397,425	399,438	397,696
Thu	02/13/03	25	40	1,600	64,000	471,898	11,797	483,126	481,217	480,887
Wed	02/12/03	25	40	1,600	64,000	462,953	11,574	483,126	481,217	480,887
Tue	02/11/03	30	35	1,225	42,875	418,200	11,949	421,911	422,019	423,126
Fri	02/07/03	30	35	1,225	42,875	403,375	11,525	421,911	422,019	423,126
Thu	02/06/03	31	34	1,156	39,304	406,365	11,952	409,668	410,650	410,684
Wed	02/05/03	30	35	1,225	42,875	410,042	11,715	421,911	422,019	423,126
Wed	01/29/03	31	34	1,156	39,304	450,555	13,252	409,668	410,650	410,684
Tue	01/28/03	27	38	1,444	54,872	522,441	13,748	458,640	457,068	458,243
Mon	01/27/03	16	49	2,401	117,649	592,249	12,087	593,314	597,652	599,941
Fri	01/24/03	25	40	1,600	64,000	530,565	13,264	483,126	481,217	480,887
Thu	01/23/03	16	49	2,401	117,649	607,422	12,396	593,314	597,652	599,941
Wed	01/22/03	19	46	2,116	97,336	570,900	12,411	556,585	557,429	554,564
Tue	01/21/03	23	42	1,764	74,088	511,988	12,190	507,613	505,994	503,917
Fri	01/17/03	21	44	1,936	85,184	513,451	11,669	532,099	531,398	528,190
Thu	01/16/03	27	38	1,444	54,872	480,494	12,645	458,640	457,068	458,243
Wed	01/15/03	25	40	1,600	64,000	501,491	12,537	483,126	481,217	480,887
Tue	01/14/03	28	37	1,369	50,653	463,772	12,534	446,397	445,228	446,798
Tue	01/07/03	32	33	1,089	35,937	424,609	12,867	397,425	399,438	397,696
Tue	12/17/02	31	34	1,156	39,304	395,015	11,618	409,668	410,650	410,684
Mon	12/16/02	32	33	1,089	35,937	374,544	11,350	397,425	399,438	397,696
Mon	12/09/02	27	38	1,444	54,872	456,519	12,014	458,640	457,068	458,243
Fri	12/06/02	30	35	1,225	42,875	397,320	11,352	421,911	422,019	423,126
Thu	12/05/02	30	35	1,225	42,875	414,418	11,841	421,911	422,019	423,126
Wed	12/04/02	30	35	1,225	42,875	408,177	11,662	421,911	422,019	423,126
Tue	12/03/02	25	40	1,600	64,000	450,841	11,271	483,126	481,217	480,887
							12,067			

Count 34

Firm Sendout Projection Based Data From 02-03
Data for Daily Temperatures < = 32 Degrees Fahrenheit

R Squared	Change	Student's T	Degrees of Freedom	Critical Value	@ 97.5% Significant
0.851102	0.851102	13.734199	33	2.04	Yes
0.851988	0.000886	0.430774	31	2.04	No
0.852661	0.000673	0.370177	30	2.04	No

Degrees of Freedom	33	31	30
97.5% Significance Level	2.04	2.04	2.04
95.0% Significance Level	1.65	1.65	1.65

LinearProjection at Zero Degrees Fahrenheit	789,202	Mcf
Linear Projection at 15 Degrees Fahrenheit	605,557	Mcf

*Student's T = Square Root((Increase * Degrees of Freedom)/(1 - R Squared))*

*Linear SO = Constant + (X * X Coefficient)*

*Quadratic SO = Constant + (X * X Coeff) + (X 1u2 * X 1u2 Coeff)*

*Cubic SO = Constant + (X * X Coeff) + (X 1u2 * X 1u2 Coeff) + (X 1u3 * X 1u3 Coeff)*

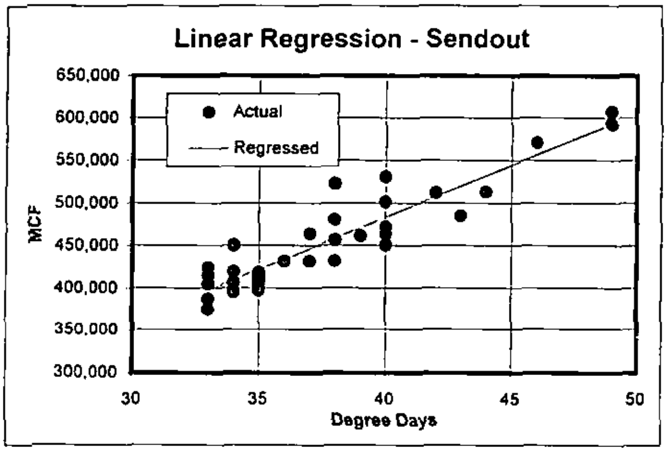
Regression Results

Winter 02-03

Based On Data for Daily Temperatures <= 32 Degrees Fahrenheit

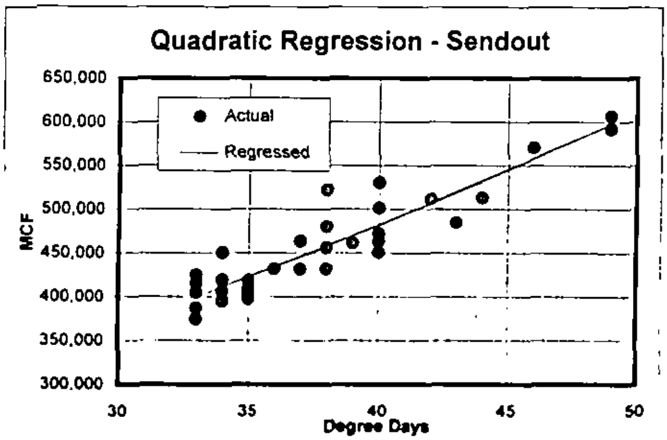
Regression Output:			Quadratic			Cubic			
Regression Output:			Regression Output:			Regression Output:			
Constant		-6595	Constant		117400	Constant		-1039013	
Std Err of Y Est		23107	Std Err of Y Est		23407	Std Err of Y Est		23740	
R Squared		0.851101558	R Squared		0.851987984	R Squared		0.852661299	
No. of Observations		34	No. of Observations		34	No. of Observations		34	
Degrees of Freedom		33	Degrees of Freedom		31	Degrees of Freedom		30	
X Coefficient(s)	12243		X Coefficient(s)	5959	78	X Coefficient(s)	93229	-2095	18
Std Err of Coef.	34442		Std Err of Coef.	14612	182	Std Err of Coef.	236161	5874	48

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winter 02-03



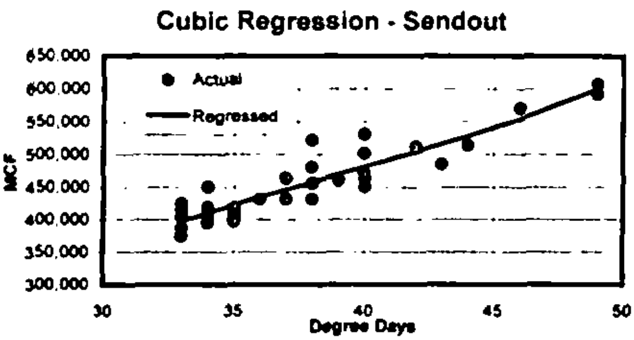
Linear Regression Output

Constant		-6595
Std. Error of Y Estimate		23107
R Squared		0.851102
Number of Observations		34
Degrres of Freedom		33
	X	
X Coefficient	12243	
Std. Err. Of Coefficeint	34442	



Quadratic Regression Output

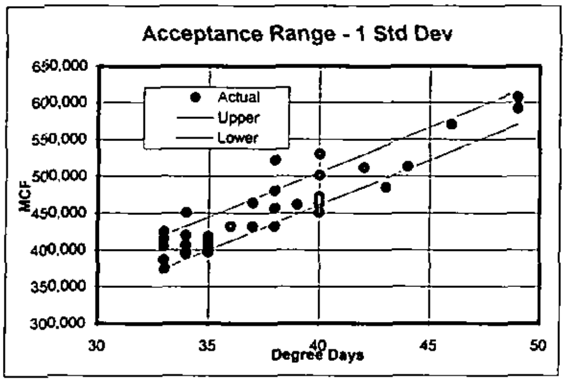
Constant			117400
Std. Error of Y Estimate			23407
R Squared			0.851988
Number of Observations			34
Degrres of Freedom			31
	X	X ^ 2	
X Coefficient	5959	78	
Std. Err. Of Coefficeint	14612	182	



Cubic Regression Output

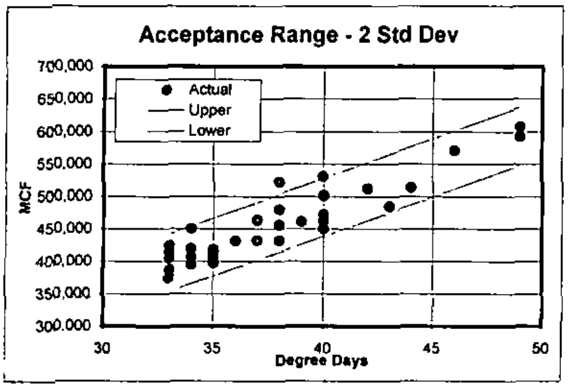
Constant		-1039013	
Std Error of Y Estimate		23740	
R Squared		0.852661	
Number of Observations		34	
Degrres of Freedom		30	
	X	X ^ 2	X ^ 3
X Coefficient	93229	-2095	18
Std. Err. Of Coefficeint	236161	5874	48

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winter 02-03



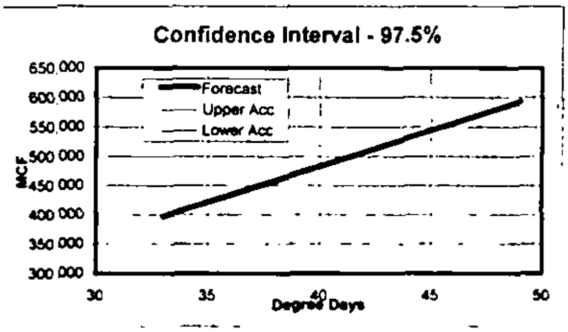
Acceptance Range @ 1 Standard Deviation

Regression Squared	502,530,228
Regression	22,417
Upper Range 1sd	478,537
Lower Range 1sd	433,703



Acceptance Range @ 2 Standard Deviation

Regression Squared	502,530,228
Regression	22,417
Upper Range 2sd	500,954
Lower Range 2sd	411,285



Confidence Interval: 97.5%

Regression Squared	502,530,228
Standard error of sendout projection	23 107
X Mean	38
T Distribution	2 04

Linear Regression Confidence Level Table

Count	Degree Days X	Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Y□dc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared (Y - Yc)²	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared (X - Xm)²	s□dyc	t*s□dyc	Lower Acc Lower	Upper Acc □dc□ + t*s□dy□d	"- 1 SD" Lower	"+1 SD" □dc□ + s□dy□dc	"- 2 SD" Lower	"+2 SD" Y□dc□ + 2s□dy□dc
1	33	387,204	397,425	(10,221)	104,472,569	(5)	23	5,877	11,971	385,454	409,396	375,008	419,842	352,591	442,260
2	33	414,921	397,425	17,496	306,100,066	(5)	23	5,877	11,971	385,454	409,396	375,008	419,842	352,591	442,260
3	33	404,972	397,425	7,547	56,952,286	(5)	23	5,877	11,971	385,454	409,396	375,008	419,842	352,591	442,260
4	33	424,609	397,425	27,184	738,977,013	(5)	23	5,877	11,971	385,454	409,396	375,008	419,842	352,591	442,260
5	33	374,544	397,425	(22,881)	523,524,940	(5)	23	5,877	11,971	385,454	409,396	375,008	419,842	352,591	442,260
6	34	419,397	409,668	9,729	94,649,059	(4)	14	5,244	10,682	398,986	420,350	387,251	432,085	364,834	454,503
7	34	406,365	409,668	(3,303)	10,908,637	(4)	14	5,244	10,682	398,986	420,350	387,251	432,085	364,834	454,503
8	34	450,555	409,668	40,887	1,671,732,884	(4)	14	5,244	10,682	398,986	420,350	387,251	432,085	364,834	454,503
9	34	395,015	409,668	(14,654)	214,729,162	(4)	14	5,244	10,682	398,986	420,350	387,251	432,085	364,834	454,503
10	35	418,200	421,911	(3,711)	13,773,895	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
11	35	403,375	421,911	(18,536)	343,583,490	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
12	35	410,042	421,911	(11,869)	140,869,995	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
13	35	397,320	421,911	(24,592)	604,744,281	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
14	35	414,418	421,911	(7,493)	56,141,646	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
15	35	408,177	421,911	(13,734)	188,631,301	(3)	8	4,701	9,576	412,335	431,487	399,494	444,328	377,077	466,746
16	36	431,722	434,154	(2,433)	5,917,959	(2)	3	4,283	8,724	425,431	442,878	411,737	456,571	389,320	478,989
17	37	431,870	446,397	(14,527)	211,030,775	(1)	1	4,028	8,204	438,194	454,601	423,980	468,814	401,563	491,232
18	37	463,772	446,397	17,375	301,877,659	(1)	1	4,028	8,204	438,194	454,601	423,980	468,814	401,563	491,232
19	38	432,012	458,640	(26,628)	709,071,706	0	0	3,967	8,081	450,559	466,721	436,223	481,058	413,806	503,475
20	38	522,441	458,640	63,800	4,070,482,139	0	0	3,967	8,081	450,559	466,721	436,223	481,058	413,806	503,475
21	38	480,494	458,640	21,854	477,594,451	0	0	3,967	8,081	450,559	466,721	436,223	481,058	413,806	503,475
22	38	456,519	458,640	(2,121)	4,498,689	0	0	3,967	8,081	450,559	466,721	436,223	481,058	413,806	503,475
23	39	461,271	470,883	(9,612)	92,396,008	1	1	4,110	8,373	462,511	479,256	448,466	493,301	426,049	515,718
24	40	471,898	483,126	(11,228)	126,070,010	2	5	4,438	9,039	474,088	492,165	460,709	505,544	438,292	527,961
25	40	462,953	483,126	(20,174)	406,979,779	2	5	4,438	9,039	474,088	492,165	460,709	505,544	438,292	527,961
26	40	530,565	483,126	47,439	2,250,452,949	2	5	4,438	9,039	474,088	492,165	460,709	505,544	438,292	527,961
27	40	501,491	483,126	18,365	337,271,071	2	5	4,438	9,039	474,088	492,165	460,709	505,544	438,292	527,961
28	40	450,841	483,126	(32,285)	1,042,344,564	2	5	4,438	9,039	474,088	492,165	460,709	505,544	438,292	527,961
29	42	511,988	507,613	4,376	19,145,843	4	18	5,495	11,194	496,419	518,806	485,195	530,030	462,778	552,447
30	43	485,096	519,856	(34,760)	1,208,244,082	5	27	6,157	12,542	507,313	532,398	497,438	542,273	475,021	564,690
31	44	513,451	532,099	(18,648)	347,743,109	6	39	6,875	14,004	518,095	546,102	509,681	554,516	487,264	576,933
32	46	570,900	556,585	14,315	204,929,822	8	67	8,419	17,150	539,435	573,734	534,168	579,002	511,750	601,419
33	49	592,249	593,314	(1,065)	1,134,516	11	126	10,891	22,184	571,130	615,497	570,897	615,731	548,479	638,148
34	49	607,422	593,314	14,109	199,051,386	11	126	10,891	22,184	571,130	615,497	570,897	615,731	548,479	638,148
Tot/Avg	38	456,120	456,120		17,086,027,741		652								

$t = 2.04$

Xm = 38

Population Standard Deviation of Regression Squared = 502,530,228

			Upper Range	Lower Range
Population Standard Deviation of Regression =	22,417	1s	478,537	433,703
		2s	500,954	411,285

Standard error of sendout projection	*23,107*
T-factor	2.04
(T factor) * (Std error of projection)	47,068

MEMORANDUM

May 2, 1997

To: B.Z. Karachiwala, PGW
Craig White, PGW

From: ICF Kaiser

Subject: *Design Weather Conditions for Supply Planning at PGW*

As part of ICF Kaiser's assignment to assist PGW in assessing its optimal supply planning configuration, we were asked to assess PGW's design day and design winter planning methodologies. To the extent that the approach to defining the design day or design winter leads to an overly conservative estimation of design conditions (that is, the estimated design conditions are higher than requirements), PGW could be over-investing in capacity or not using its existing capacity optimally.

ICF evaluated the design winter gas demand estimation methodology currently used by PGW. As a first step, we reviewed the design winter and design day demand estimation methodologies and evaluated the critical assumptions underlying the methodologies using historical data and statistical tools.

PGW estimates its design day demand using a valid statistical procedure. PGW's degree day estimates for a design winter and a design day are *consistent* with the historical weather data and the degree day estimates used by other utilities in the region. The following table compares PGW's design winter with the historical weather data.

Data Set (1948-1996)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Winter Degree Days	554	884	1018	869	703	4025*
Historical Peak Winter Degree Days	743	1219	1390	1170	997	4640*
Lower limit of 95% confidence level (Mean - 2 std.dev.)	395	615	717	644	504	3353*
Upper limit of 95% confidence level (Mean + 2 std.dev.)	705	1157	1318	1093	901	4698*
PGW's Design Winter Degree Days	617	994	1160	987	808	4566
Probability of PGW's Design Winter	1:5	1:4	1:6	1:7	1:7	1:16

Notes.
* Individual month estimates do not add up to this total, because it has been calculated independently using the historical winter season data or standard deviation for the season total.

These statistical estimates indicate the following:

- PGW's design winter is 74 degree days short of 48-year historical peak winter.
- PGW's monthly design winter conditions are 126 to 230 degree days less than 48-year historical monthly peak winter conditions.
- PGW's design winter conditions lie well within the 95 percent confidence level. This indicates that the likelihood of a winter being colder than PGW's design winter is greater

than 5 percent. This suggests that PGW's design winter conditions are not overly conservative.

- A winter that is *as cold as or colder than* PGW's design winter is likely to occur once in 16 years.

This memorandum summarizes the results of this study in two sections: (1) a summary of the methodology used by PGW to estimate design conditions; and (2) a statistical analysis of PGW's design winter. We have supplied more detail on our assessment in two attachments (Appendices A & B) to this memorandum.

Overview of PGW's Design Winter/Day Gas Demand Estimation Methodology

The design day and design winter are the periods which define the largest amount of gas that PGW must deliver to meet system requirements and to maintain system integrity. The design day is the coldest day resulting in the highest expected coincident demand on the system; the design winter is defined as the coldest experienced winter, combined with the coldest experienced January (historically, the coldest month in Philadelphia). As such, the design conditions are used to for determining annual total storage and pipeline capacity, storage injection and withdrawal patterns, and supply plans for the PGW system. Design sendout is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather.

As noted above, this memorandum addresses PGW's approach to describing design weather conditions. We have not evaluated PGW's approach to estimating the demand response or the number of customers. Rather, we have focused on addressing the issue of whether the design day or winter conditions are in excess of what may be considered statistically reasonable. The technical description of each is defined as follows:

- The design day at PGW is a day when the mean temperature is zero degree F. or 65 degree days. Under these conditions, PGW plans to send 714 Mmcf of natural gas to firm (i.e., after the interruptible customers have been dropped from the system) on-system customers. Because PGW owns about 291 Mmcf of pipeline capacity from supply areas and can vaporize between 450 and 540 Mmcf of LNG on any day, design day conditions appear not to be constraining even without employing PGW's approximately 160 Mmcf per day of peak storage withdrawal capacity.

- Design winter describes a colder than normal winter combined with a colder than normal January. The design winter has 4,566 degree days; the design year has 5,280 degree days.

<u>The design winter demand</u> is estimated by summing the demands of each customer rate class over the winter period (November through March). More specifically, the following equation is used to estimate the total monthly demand for each rate class of customers.

For each customer rate class:

Monthly Demand = No. of customers * UAF * [(Domestic Load Adjustment Factor
* (DOM * 12/365 * No.of days in the month)] + [(CFDD * Heating Degree Days)
* Heating Adjustment Factor)]

where

DOM, domestic load factor per customer per month, is the minimum or base load requirement;
CFDD is the heating demand factor per customer per degree day; and
UAF is the unaccounted for gas adjustment factor per customer.

The Domestic Load Adjustment Factor is used to adjust the seasonal variation in the non-heating gas demand (i.e., domestic load). Heating Adjustment Factor, on the other hand, is used to adjust the seasonal variation in the gas demand for space heating (i.e., sendouts for heating), due to differences in the responsiveness of customers to changes in heating degree days between seasons.[1]

DOM factor is calculated for each customer rate class (excluding interruptible customers) by adjusting the estimated (or trial) sendouts--during the previous year's summer months, July through September--by the Domestic Load Adjustment Factor. As such the DOM factor accounts for baseload, non-weather demand by PGW's customers. CFDD is calculated for each customer rate class (excluding interruptibles) by adjusting the estimated total heating gas demand by *actual* heating degree days--during the previous year's peak winter months, December through February--and the Heating Adjustment Factor.

The design winter gas demand for each customer rate class is calculated by using PGW's design winter degree days. PGW's design winter consists of 4,566 heating degree days over the 151-day period of November through March.

Design day gas demand projections are made using a statistically estimated equation. More specifically, using linear regression analysis, a peak winter day gas demand equation is estimated by regressing the actual sendouts on those weekdays (excluding holidays) during the previous year's winter season when temperature was 32°F or below. The gas demand equation is:

$$\text{Weekday actual sendout} = a + b * \text{Degree Days} + \varepsilon$$

where
a is the intercept;
b is the slope; and
ε is the residual, not captured by the estimated demand equation.

The design day consists of 65 degree days or a day with a mean temperature of zero degree F with a design hour of -5°F. Using the regression estimates of a and b and 65 degree days, design day gas demand is calculated. An additional 5% contingency is normally added to the estimated total gas demand.

To attach a degree of confidence (e.g., 95%) to the demand estimate thus calculated, an interval of gas demand estimates are developed using (plus or minus two times) standard deviation of the weekday actual sendouts. This implies that 95% of the time actual gas demand will be within the interval of estimates thus computed. This establishes the response of the firm customers under cold weather conditions. Although this demand equation can be used to estimate the total gas

[1] For example, the gas demand for space heating in response to an increase in the number of heating degree days during September is likely to be less than the gas demand for space heating in response to a corresponding increase in the number of degree days during January.

- Historically, *winter temperature (excluding wind-chill effect) of 5°F* or below always occurred in January. In addition, on average, coldest day *of the year* is *more likely* to be a day in January than in any other month. These imply that *PGW's* planning for the design day to occur in January is *consistent* with the historical data.

- Historically, winter temperature (excluding wind-chill effect) in March has always been above 10°F. In addition, on average, the likelihood of the coldest day of the year occurring *in March, rather than in any other month, is 4%.* Therefore, it is *consistent* with the *historical data to say that Design Day conditions are not likely to occur in* March.

To evaluate if PGW's design winter estimate, we (1) estimated a set of alternative design winters based on historical weather data and simple statistical criteria, and computed associated risks of not being able to meet the gas demand due to colder than alternative design winters: (2) surveyed other utilities in the region and compiled their design winter criteria and estimates: and (3) compared these estimates to those of PGW's. Similar analysis was performed on PGW's design day estimate. The results of our analyses suggest that PGW's design winter and design day are *reasonable estimates*. Appendix B contains the statistical results of these analyses.

Conclusion

As mentioned earlier, design sendout is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather. We analyzed PGW's degree day estimates for design winter/day, using historical data, statistical tools, and degree day estimates of other utilities in the region. The results of our analysis indicate that the PGW's degree day estimates are consistent with the historical weather data and the degree day estimates of other utilities in the region. We examined the PGW's winter gas demand estimation methodologies and found them to be satisfactory.

If you have any questions or comments, please call Leonard Crook at (202)-862-2952.

demand on other severe winter days (ranging from 33 to 65 degree days), it will not be statistically valid to use this equation to estimate gas demand on days when the weather conditions are milder.

ICF's Assessment of Design Winter Estimation Methodology

A critical factor in estimating design winter gas demand is the number of heating degree days. ICF evaluated PGW's estimate of the design winter total (i.e., 4,566 degree days) and individual design winter monthly degree days to determine whether better estimates could be generated using purely statistical approaches. Historical winter degree days during the past 48 years (1948-95) were statistically analyzed and compared to the PGW's design winter to determine the extent to which PGW's design winter is representative of historically colder than average winters. Following are the key findings.

- PGW's design winter, as expected, *exceeds* the historical mean by about 540 degree days; however, it is about 75 degree days *lower* than the historical maximum.

- On average, once in every 16 years, a winter is likely to be *as cold as or colder than* PGW's design winter.

- PGW's ranking of design winter months are, on average, *consistent* with the ranking of historical winter months. January is the coldest month; December is the second coldest month, followed by February; March is the fourth coldest month; and November as the fewest heating degree days.

- The PGW's design winter is *consistent with* the design winters adopted by other utilities in the region.

- On average, PGW's design winter is *less likely* to occur than (1) any of its design winter month, (2) a combined design December and January, or (3) a combined design December through February. The design winter, however, is *more likely* to occur than a combined design December through March. Essentially, this indicates that design months occur randomly, independent of design winter conditions. It may be more likely that a string of colder than normal winter months will occur than a design winter; but it is less likely that these months will include March.

- There is *no correlation* between January, February, and March heating degree days. Although statistically significant relationships do exist between monthly heating degree days, these relationships are *highly sensitive* to the sample data set used. Thus, one cannot say if March will be colder or warmer than normal based on February or other winter months.

- PGW's Design Day temperature, as expected, *exceeds* the historical mean by over 10 degree days; however, it *almost equals* the historical peak.

- On average, once in every 16 years, temperature (excluding wind-chill effect) is likely to be 2°F or below on the coldest day of the year. This implies that PGW's design day is *almost as likely* to occur as its design winter.

APPENDIX A

PHILADELPHIA GAS WORKS' (PGW) DESIGN WINTER/DAY NATURAL GAS DEMAND ESTIMATION[1]

The design day and design winter are the periods which define the largest amount of gas that PGW must deliver to meet system requirements and to maintain system integrity. The design day is the coldest day resulting in the highest expected coincident demand on the system; the design winter is defined as the coldest experienced winter, combined with the coldest experienced January (historically, the coldest month in Philadelphia). As such, the design conditions are used to for planning annual total capacity and supply necessary for the PGW system. Following are PGW's design winter conditions.

- Design winter describes a colder than normal winter combined with a colder than normal January. The design winter consists of 4,566 degree days over the 151-day period of November through March; the design year has 5,280 degree days.

- The design day at PGW is a day when the mean temperature is 0°F, or 65 degree days, with a design hour of -5°F.

Design sendout (i.e., gas demand) is a function of three factors: (1) weather expressed in degree days, (2) number of customers, and (3) the demand response of those customers to cold weather. PGW's design sendout estimation methodologies are described below in two parts: (1) Design Winter demand and (2) Design Day demand.

I. DESIGN WINTER DEMAND ESTIMATION

Design winter demand comprises of domestic load and heating demand. Domestic load is determined by number of customers and domestic load requirement per customer. Heating demand, on the other hand, is determined by number of customers, heating degree days, and heating demand requirement per customer per degree day.

The design winter demand is estimated by summing the demands of each customer rate class over the 151-day winter period (November through March). More specifically, the following equation is used to estimate the total monthly demand for each rate class of customers.

For each customer rate class:

Monthly Demand = No. of customers * UAF * [{Domestic Load Adjustment Factor
* (DOM * 12/365 * No.of days in the month)} + {(CFDD * Heating Degree Days)
* Heating Adjustment Factor}]

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[1] *Our understanding of PGW's design winter/day* demand estimation methodology is primarily based on our review of PGW's document "Gas Cost Rate (GCR) Fiscal Year 1995-96 for the Philadelphia Gas Works,Volume I--Gas Supply/Demand Strategy, Section A: Statistical Reference Data Schedules." submitted before the Philadelphia Gas Commission, August 1995. This document contains the methodology used by PGW to estimate (in March 1995) its annual gas demand for 1995-96 and for every planning year thereafter until 2000-01. In this appendix, we have generalized the methodology without making reference to any particular year.

where

DOM, domestic load factor per customer per month, is the minimum or base load requirement;

CFDD is the heating demand factor per customer per degree day; and

UAF is the unaccounted for gas adjustment factor per customer.

The methodologies used to estimate each of these components are described below in detail.

Domestic Demand

Domestic gas demand or baseload is estimated for each customer rate class by multiplying minimum load requirement per customer (i.e., DOM) by PGW's projections of number of customers in that rate class. The methodologies for estimating DOM and the domestic load adjustment factor are explained below.

Domestic Load Factor (DOM)

DOM is the per customer minimum or base load requirement, which varies across customer rate class. It is calculated (1) by adjusting the estimated (or trial) sendouts--during the previous year's summer months of July through September--calculated for each customer rate class (excluding interruptible customers) by the domestic load adjustment factor described below, and (2) by dividing the estimates by the number of customers in each rate class.[2]

Domestic Load Adjustment Factor

The Domestic Load Adjustment Factor is used to adjust the seasonal variation in the non-heating gas demand (i.e., domestic load). This factor is calculated by adjusting (previously) estimated sendout to actual sendout, during the previous year's summer months of July through September.

Domestic Load Adjustment Factor

= 3 month-total of actual firm sendout / 3-month total estimated firm sendout

Heating Demand

Heating demand is determined by the following three factors: (1) demand response of customers to cold weather; (2) number of degree days; and (3) number of customers. For each customer rate class, heating demand for a design winter is calculated by multiplying the following factors: (1) heating requirement per degree day per customer; (2) PGW's design winter degree days; and (3) PGW's projections of number of customers.[3] To this estimate a heating demand adjustment factor is applied to correct for the seasonal variation in the gas demand for space heating.

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[2] We understand that trial sales were calculated based on the previous year's load calculation.

[3] Number of customers is based on projections developed by the Marketing department and historical assessments of customer attrition.

HEATING FACTOR (CFDD)

It is the heating gas demand requirement per degree day per customer. It varies by customer rate class. It is calculated as follows: first, Trial Heating Factor (Trial CFDD) is calculated; second, heating adjustment factor is calculated using DOM, Trial CFDD, and baseload estimates during peak winter months for each customer rate class; and last, Final CFDD is calculated by adjusting trial CFDD by the heating adjustment factor. The heating factor estimation methodology is described below in detail.

TRIAL HEATING FACTOR (TRIAL CFDD): It is calculated by dividing the total amount of gas demanded for heating (only) by the total degree days during the previous year's peak winter months, December through February.

Trial CFDD = Total Gas Demand for heating over previous year's peak winter months (Dec.-Feb.) / total degree days during this period

This calculation involves two steps:

(1) Calculate total heating gas demand for each of the 3 months (MCF) by subtracting the DOM factor from the actual sendout. For example, *for December*:

$$MCF_{dec} = [\{(\text{Actual Sales}_{dec}/\text{Number of Customers}_{dec}) - DOM\}/\text{Degree Days}_{dec}] * \text{Degree Days}_{dec}$$

(2) Add MCF_{dec}, MCF_{jan}, and MCF_{feb}, and divide by total degree days during this three month-period.

$$\text{Trial CFDD} = (MCF_{dec} + MCF_{jan} + MCF_{feb}) / \text{Degree Days}_{dec+jan+feb}$$

Note: Degree days vary by customer rate class. Calendar degree days are used for customer rate class 1-18; cycle degree days are used for customer rate class 37-57; and previous month's cycle degree days are used for customer rate class 36.

FINAL CFDD: Final CFDD is calculated by adjusting trial CFDD by the heating adjustment factor (which is described below) as follows:

Final CFDD = Trial CFDD * Heating Adjustment Factor.

HEATING ADJUSTMENT FACTOR

Heating Adjustment Factor is used to adjust the seasonal variation in the gas demand for space heating that arises from differences in the responsiveness of customers to changes in heating degree days between seasons. It is calculated by adjusting the (previously) estimated sendout to the actual sendout during the previous year's peak winter months.

To avoid over-or under projections of heating gas demand, PGW (1) calculates the difference between actual and estimated total gas sendouts during the previous year's peak winter months, December through February and (2) inflates (deflates) the planned sendout by adding (subtracting) the difference if the actual sendout exceeded (fell below) estimated sendout. Heating Adjustment Factor is calculated as follows:

Heating Adjustment Factor = [(Actual Sendout - Estimated Sendout)/(Estimated Sendout - Baseload)] + 1

where Estimated Sendout is calculated using trial CFDD and Baseload is calculated for the peak winter months, setting trial CFDD to zero.

Heating adjustment factor of, for example, 1.0735 implies the following: (1) actual total sendout (during the previous year's peak winter months) exceeded the estimated total sendout (as indicated by the greater than unity value of the heating adjustment factor is); (2) this difference between estimated and actual sendouts accounts for about 7.35% of the estimated heating demand; and (3) in the future, heating sendouts will be increased by 7.35% of the estimated sendout.

The heating adjustment factor remains constant across all customers and customer rate classes.

UNACCOUNTED FOR GAS FACTOR (UAF)

UAF is used to adjust the difference between actual sendout and gas consumption by customers. This difference can arise from factors, such as pipeline leaks, pressure differentials, and unmetered deliveries. For example, UAF of 1.031 indicates 103.1 Mcf of natural gas must be sent out to meet 100 Mcf of gas demand. Therefore, UAF is usually calculated by dividing actual total gas sendout by total gas consumed by customers in that month. This factor remains constant across all customers and customer classes.

PGW'S DESIGN WINTER DEGREE DAYS

PGW's design winter has 4, 566 degree days during the 151 days of a winter season. Following is the monthly spread:

617 - November
994 - December
1,160 - January
987 - February
808 - March

II. DESIGN DAY DEMAND ESTIMATION

Design day gas demand projections are made using a statistically estimated equation. More specifically, using linear regression analysis, a peak winter day gas demand equation is estimated by regressing the actual sendouts on those weekdays (excluding holidays) during the previous year's winter season when temperature is 32°F or below.

For example, design day projections for 1995-96 were developed by PGW through a demand equation, estimated by regressing the actual sendout when daily temperature was 32°F or below (during 1994-95 winter weekdays, i.e., excluding weekends and holidays) on a constant and degree days during the same period. The 5% contingency normally applied to the baseload was not used, because, the near design conditions of continuous severe weather was experienced during 1994-95. The following is the design day gas demand model, estimated by PGW.

$$\text{Gas Demand} = a + b_1 * \text{Degree Days} + b_2 * \text{Degree Days}^2 + b_3 * \text{Degree Days}^3 + \varepsilon$$

where

a is the intercept;

b_1 is the slope;

b_2 & b_3 indicate the shape; and

ε is the residual, not captured by the estimated demand equation.

Using 22 observations, three models were estimated by PGW with linear, quadratic, and cubic terms for degree days (i.e., Degree Days, Degree Days^2, and Degree Days^3 respectively). The model with linear term for degree days (hereafter, referred to as linear model, for simplicity) fitted the data better than the others, with an adjusted R^2 of 0.905.[4] The adjusted R^2 value, however, informs us that about 90% of the variation in the actual sendout data are explained by the estimated demand equation.

PGW's linear model estimates are: a =-16.883 and b_1=12.275. We observe that the negative estimate of a is not consistent with the conventional wisdom, because it implies that domestic load per customer is negative. Nevertheless, the objective is to estimate a demand equation that fits actual peak winter day sendout data the best, so that in the future, best possible design day sendout estimates can be developed using the estimated demand equation. Therefore, it is *reasonable* to use the model estimates to calculate design day sendouts.

Design day gas demand is calculated using the linear model estimates of a and b and 65 degree days. To attach a degree of confidence (e.g., 95%) to the demand estimate thus calculated, an interval of gas demand estimates are developed using (plus or minus two times) standard deviation of the weekday actual sendouts. This implies that 95% of the time actual gas demand will be within the interval of estimates thus computed. This establishes the gas demand response of PGW's firm customers under cold weather conditions.

Although this demand equation estimated by PGW can be used to estimate gas demand on other severe winter days (ranging from 33 to 64 degree days), it will not be statistically valid to use this equation to estimate gas demand on days when the weather conditions are milder, because it is estimated based on a restricted (i.e., only when temperature was 32°F or below) sendout sample and because the gas demand response of customers may be different at milder weather conditions.

[4] ICF calculated *Adjusted* R^2 from PGW's unadjusted R^2 estimate (of the linear gas demand model), by adjusting it for the degrees of freedom.

APPENDIX B

ARE PGW'S DESIGN CONDITIONS REPRESENTATIVE OF THE HISTORICAL WINTER?

A critical factor in estimating design winter gas demand is the number of heating degree days. ICF evaluated PGW's estimate of the design winter total (i.e., 4,566 degree days) and individual design winter monthly degree days to determine whether better estimates could be generated using purely statistical approaches. Historical winter degree days during the past 48 years (1948-95) were statistically analyzed and compared to the PGW's design winter to determine the extent to which PGW's design winter is representative of historically colder than average winters.[1] The results and the findings of these analyses are presented below in terms of questions and answers (Qs & As). These Qs & As are presented in two parts: (1) Design Winter and (2) Design Day conditions.

I. DESIGN WINTER CONDITIONS

1. What are the sample statistics of the Historical Winter Degree Days?

Data set (1948-95)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Degree Days	554	884	1,018	869	703	4,025[b]
Historical Peak Degree Days	743	1,219	1,390	1,170	997	4,640[b]
No. of Sample Observations	49	49	48	48	48	48
Sample Standard Deviation	80	135	150	112	99	336
Variability of Historical Data Relative to Mean[a] (%)	14	15	15	13	14	8[b]
PGW's Design Degree Days	617	994	1,160	987	808	4,566

Notes:
[a] It is coefficient of variation, calculated as (sample standard deviation/sample mean)*100.
[b] Individual months do not add up to this total, because it has been calculated independently using the historical winter season data or the standard deviation for the season total

Findings:

- PGW's design winter, as expected, ***exceeds*** the historical mean by about 540 degree days; however, it is about 75 degree days ***lower*** than the historical maximum.

- PGW's ranking of design winter months are, on average, *consistent* with the ranking of historical winter months. January is the coldest month; December is the second coldest month, followed by February; March is the fourth coldest month; and November as the fewest heating degree days.

- The number of total degree days during winters is less variable (by about 5%-7%) than the number of degree days during individual winter months. This implies that if historical data is used to develop a design winter, more reliance can be placed on a design winter,

[1] Bowen, K. Earl and Starr, Martin K. 1982. *Basic Statistics for Business and Economics*. McGraw-Hill Book Company, New York.

developed using historical mean (such as mean ± 1.5 standard deviation) than on any similarly developed individual design winter month.

2. What is the probability that PGW's design winter conditions will occur?

Design Winter Months	Number of PGW'sDesign Degree Days	No. of times a design or a colder winter occurred during 1948-96.	Historical Probability that a design or a colder winter will occur (number of years)	Historical Probability that a design or a colder winter will occur (%)
November	617	9	1/5	18
December	994	12	1/4	24
January	1160	8	1/6	17
February	987	7	1/7	15
March	808	7	1/7	15
Dec. & Jan.	2154	7	1/7	15
Dec. through Feb.	3141	4	1/12	8
Dec. through March	3949	2	1/24	4
Nov. through Feb.	3758	4	1/12	8
Design Winter	4566	3	1/16	6

Findings:

- On average, once in every 16 years, a winter is likely to be *as cold as or colder than* PGW's design winter.

- On average, PGW's design winter is *less likely* to occur than (1) any of its design winter month, (2) a combined design December and January, or (3) a combined design December through February. The design winter, however, is *more likely* to occur than a combined design December through March. Essentially, this indicates that design months occur randomly, independent of design winter conditions. It may be more likely that a string of colder than normal winter months will occur than a design winter; but it is less likely that these months will include March.

3 What do winter conditions during early winter months inform us about the winter conditions during rest of the winter season? (Anecdotally, observers think that there may be a positive correlation between early winter and severity of winter, but apparently there does not seem to exist any scientific meteorological relationship.)

To examine if cold weather in early winter is any indicator of cold weather in late winter months or rest of the winter, correlation coefficients (r) were calculated and analyzed for several sub-sample data sets. The data set was divided on the basis of severity of winter and November winter conditions as follows:

(i) complete data set 1948-95;
(ii) only those years, when winter conditions were average or milder, i.e., 4,025 degree days or below;

(iii) only those years, when winter conditions were colder than average, i.e., above 4,025 degree days;
(iv) only those years, when winter was much colder than average, i.e., at least 4,100 degree days;
(v) only those years, when winter conditions during November were average or milder, i.e., 554 degree days or below;
(vi) only those years, when November was colder than average, i.e., above 554 degree days; and
(vii) only those years, when November was much colder than average, i.e., above 600 degree days.

Findings:

- There is *no correlation* between January, February, and March heating degree days. Although statistically significant relationships do exist between monthly heating degree days, these relationships are *highly sensitive* to the sample data set used. Thus, one cannot say if March will be colder or warmer than normal based on February or other winter months.

4. Compare PGW's Design Winter with those of other utilities in the region.

Utilities	Design Winter Criterion	Time period used	No. of Design Degree Days
PGW, Philadelphia, PA			4,566
UGI, Reading, PA	Mean of 40 winters +1.645*std.dev.	1957-95	4,616
PECO, Philadelphia, PA	Mean of 28 winters * 112%	1968-95	4,483
South Jersey Gas, Folsom, NJ	30 year-peak winter	1966-95	4,613
Elizabethtown, Bedminster, NJ	30 year-peak winter	1966-95	4,613
Historical Maximum		1948-95	4,640

Source: ICF Kaiser's Survey and Historical Temperature Data Analysis.

Findings:

- The PGW's design winter is *consistent with* the design winters adopted by other utilities in the region.

5. Is there a statistical criterion that can be used to estimate design winter conditions, based on historical data?

The objective is to evaluate PGW's design winter conditions against statistically developed winter conditions; if PGW's design winter conditions are much colder than the winter conditions statistically developed, for example, with 95% confidence level, PGW's design winter conditions could be considered overly conservative. Under such conditions PGW could be over-investing in capacity or under-utilizing existing capacity.

A principal advantage of using statistical methodology to estimate design winter conditions is that it would us to construct intervals of estimates, within which winter conditions can be expected to lie 95% or 99% of the time. Therefore, a statistical criterion could be to develop *estimates of winter conditions such that 95% of the time winter conditions will be within this* range of estimates. Validity of such estimates, however, is dependent upon the validity of the assumption that we make about the underlying distribution of the weather conditions (that extend beyond our sample data pertaining to 1948-95). Therefore, we have developed below confidence intervals for winter conditions with and without assumption about the underlying distribution of winter weather conditions.

Assuming that the winter degree days are <u>normally distributed</u> about the mean, (i) 68% of winter degree days will lie between the following interval of sample mean ± 1 standard deviation, (ii) 95% of winter degree days will lie between the interval of sample mean ± 2 standard deviation, and (iii) 99.7% of winter degree days will lie between the interval of sample mean ± 3 standard deviation.

However, if winter degree days are <u>not</u> normally distributed, the above conclusions will not hold and the confidence level could be lower. Nevertheless, we can conclude that (i) *at least* 75% of winter degree days will lie between the interval of sample mean ± 2 standard deviation and (ii) at least 88% of winter degree days will lie between the interval of sample mean ± 3 standard deviation (*Chebyshev Inequality Theorem*).

Month	PGW's Design Winter	Sample mean - 1 Std. Dev	Sample mean + 1 Std. Dev	Sample mean - 2 Std. Dev	Sample mean + 2 Std. Dev
Nov	617	473	628	395	705
Dec	994	751	1022	615	1157
Jan	1160	867	1168	717	1318
Feb	987	756	981	644	1093
Mar	808	603	802	504	901
Season Total	4566	3689[a]	4362[a]	3353[a]	4698[a]

<u>Note</u>: [a] Individual months do not add up to this total, because it has been calculated independently using the standard deviation for the season total.

<u>Findings:</u>

- PGW's design winter falls within the 95% confidence interval estimates, developed assuming winter conditions are normally distributed. This indicates that there is *no statistically based criterion* that can be used to optimally estimate PGW's design winter better. Nevertheless, *there may be other policy* criteria--such as cost-benefit (i.e., and an acceptable trade off between risks and potential cost savings) criterion and maximum acceptable risk criterion--that can be used to optimally estimate design winter conditions.

6. To facilitate setting up an optimal policy criterion, evaluate the risks associated with alternative design winters and compare them to PGW's design winter.

To estimate an optimal design winter for PGW, we *need to establish* a probability or a cost-benefit "*criterion*"--such as (a) a probability (i.e., relative frequency) limit *above* which a winter may not be colder than a design winter; or (b) a criterion for an acceptable trade-off between the risks and the potential cost-savings from reduced supply capacity due to reduced design winter conditions. We observe that currently, PGW does not appear to have any such criterion.

Setting up an optimal criterion, however, will require evaluating a wide range of alternative criteria. To facilitate such a comparison, we established simple *alternative* design winter criteria. [Note: there is no significance attached to these design winter criteria; the design winters calculated must be simply considered as alternative thresholds without any importance attached to them.] Based on these criteria, alternative design winters and probabilities of winter being *as cold as or colder than* these design winters were calculated. These results, presented below, are then compared to the PGW's design winter.[3]

Alternative Design Winter Criterion	Alternative Design Winter (Deg.days)	No. of times the winter was *as cold as or colder than* the alternative design winter during the past 48 years	Probability that a winter is *as cold as or colder than* the *alternative* design winter (years and %)
Sample Mean (upper limit of the 99% confidence interval) (1948-95)	4,157	19	2/5 (=40%)
Sample Mean + 1 standard deviation	4,362	10	1/5 (=21%)
(Sample Mean + 1 std. dev.) + 1% of this total, added as contingency	4,406	7	1/7 (=15%)
(Sample Mean + 1 std. dev.) + 2% of this total, added as contingency	4,450	6	1/8 (=13%)
(Sample Mean + 1 std. dev.) + 3% of this total, added as contingency	4,493	5	1/9 (=10%)
(Sample Mean + 1 std. dev.) + 4% of this total, added as contingency	4,537	4	1/12 (=8%)
(Sample Mean + 1 std. dev.) + 5% of this total, added as contingency	4,580	3	1/16 (=6%)
PGW's Design Winter	4,566	3	1/16 (=6%)

Findings:

- If PGW's design winter is reduced by about 115 degree days (to 4,450), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 100%.

- If PGW's design winter is reduced by about 75 degree days (to 4,493), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 65% (i.e., two-third).

- If PGW's design winter is reduced by about 30 degree days (to 4,537), the *risk* of *not being able to meet the total winter gas demand* will *increase* by about 35% (i.e., one-third).

[3] Because, winter conditions that are below planned design winter conditions are always preferred, we assume that if a winter is as cold as or colder than the design winter, there will be a risk of not being able to meet total winter gas demand.

II. DESIGN DAY CONDITIONS

7. What are the sample statistics of historical monthly peaks?

Data Set (1948-95)	Nov	Dec	Jan	Feb	Mar	Winter Season
Average Daily Temperature (°F)	47	36	32	34	42	38*
Lowest Temperature Ever (°F)	21	6	1	6	15	1*
Sample Mean of monthly peak day temperatures (°F)	32	21	16	18	27	13*
Standard Deviation of peak day temperatures	4.5	5.4	7.2	5.4	5.4	5.3*
PGW's monthly Peak Day/Design Day Winter Temperature (°F)	22	11	0	5	18	0
Lower Limit of the 95% Confidence Interval for monthly peak day temperature (Peak Mean - 2 std.dev) (°F)	23	21	18	21	21	21*
Upperlimit of the 95% Confidence Interval for monthly peak day temperature (Peak Mean + 2 std.dev) (°F)	41	32	30	29	38	24*
By how many degrees PGW's monthly peak day/Design Day temp. is colder than the 95% confidence interval? (°F)	1	10	18	16	3	21*
Lower Limit of the 99% Confidence Interval for monthly peak day temperature (Peak Mean - 3 std.dev) (°F)	19	5	-6	2	11	-3*
Upperlimit of the 99% Confidence Interval for monthly peak day temperature (Peak Mean + 3 std.dev) (°F)	46	37	38	34	43	29*
No.of observations in the sample	49	49	49	48	48	48

* Individual months do not add up to this total, because it has been calculated independently using the historical winter season data or the standard deviation for the season total.

Findings:

- PGW's Design Day temperature is *almost equal to* the historical peak.
- PGW's Design Day temperature, as expected, *exceeds* the mean of historical peaks by over 10 degree days.
- On average, once in every 16 years, temperature (excluding wind-chill effect) is likely to be 2°F or below on the coldest day of the year. This implies that PGW's design day is *almost as likely* to occur as its design winter.

8. What is the historical frequency distribution of cold days (i.e., ≤0°F, 5-10°F, 10-15°F, 15-20°F, 20-25°F, and 25-30°F) during the winter months?

Winter Temperature	Nov	Dec	Jan	Feb	Mar	Winter	Historical	PGW's

(during 1948-95)	(days)	(days)	(days)	(days)	(days)	Season (days)	Yearly Average (days)	Design Winter (days)
0°F or below	0	0	0	0	0	0	0	1
1°F - 5°F	0	0	7	0	0	7	0.1	4
6°F -10°F	0	2	16	10	0	28	0.6	0
11°F -15°F	0	12	45	16	1	74	2	5
16°F - 20°F	0	57	105	73	8	243	5	11
21°F - 25°F	3	111	190	132	32	468	10	10
25°F - 30°F	22	196	254	220	68	761	16	20
Total number of days winter temperature was 30°F or below	25	378	617	451	109	1,581	33	51
Average no. of days in a year winter temperature was 30°F or below	0.5	8	12	9	2	33	-	-

Findings:

- *Historically, winter temperature of 5°F or below always occurred in January.* This implies that PGW's planning for the design day to occur in January is *consistent* with the historical data.

- Historically, winter temperature in March has always been above 10°F; over the past 48 years, fewer than 5 times, the temperature has been 15°F or below during March. Therefore, it is *consistent* with the historical data to say that Design Day conditions are *not likely* to occur in March.

9. What is the probability that the coldest winter day in a year will occur in January?

Sample Data Set: 1948-95	Nov	Dec	Jan	Feb	Mar
Mean of monthly peak day temperatures (°F)	32	21	16	18	27
Lowest Temperature ever (°F)	21	6	1	6	15
No. of times the coldest day in a year occurred this month *during the past 48 yrs.*	0	10	23	16	2
Probability that the coldest day in a year will fall in this month (number of years)	0	1/5	1/2	1/3	1/24
Probability that the coldest day in a year will fall in this month (%)	0	20	47	33	4
PGW's *Monthly Peak day/Design Day Winter* Temperature (°F)	22	11	0	5	18

Findings:

- On average, coldest day of the year is *more likely* to be a day in January than in any other month. This implies that PGW's planning for the design day to occur in January is *consistent* with the historical data.

- On average, the likelihood of the coldest day of the year occurring in March is 4%. In other words, 96% of the time, the coldest day of the year is likely to occur in December, January, or February. Therefore, it is *consistent* with the historical data to say that coldest day of the year is *less likely* to occur in March.

10. How does PGW's design day compare with those of other utilities in and around the region?

To evaluate PGW's design day with that of other utilities in the region, we compiled design day criteria adopted by other utilities in the region. To facilitate comparison across the design day planning criteria adopted by utilities and to compare other utilities' design day sendout planning with that of PGW's, we estimated relative potential design day sendout. It was calculated as follows: Relative potential Design Day Sendout = Sendout when the temperature is 0°F, which is assumed to equal 100% * [(65 degree days - Design Day Mean Temp.)/65] * (1 + PGW's sendout adjustment factor for wind speed + reserve margin). This formula assumes that sendout increases linearly to increases in wind speed and heating degree days. The following table compares the design day adopted by other utilities in the region with PGW's design day.

Utilities	Design Day Mean Temperature (°F)	Probability of Design Day occurrence[a] (years)	Design Day Wind Speed (mph)	Design Day Reserve Margin (%)	Increase in heating demand resulting from Design Day Wind Speed[b] (%)	Relative Potential Design Day Sendout[c] (%)
PGW, Philadelphia, PA	0	-	-	-	-	100
Baltimore Gas & Electric, Baltimore, MD	2.7	1:25	15	10.7	5	111
Peoples Natural Gas, Pittsburg, PA	-9	1:15	15.8	10[d]	5.6	132
UGI, Reading, PA	-1.1	1:20	-	-	-	102
Washington Gas Light, Washington, DC	5	-	17	0.6	6.2	99
48-year Historical Peak (1948-96)	1	1:48	n/a	-	-	98

Sources: (1) PGW's documents on Design Day Planning and Sendout Estimation; (2) "Analysis of LDC Peak Day Planning," prepared by Fosters Associates for American Gas Association. *Gas Energy Review*, March 1996, pp:7-10. (3) ICF Kaiser's Historical Temperature Data Analysis.

Notes:

[a] It is a design day planning criterion adopted by some utilities.

[b] It is the sendout adjustment factor used by PGW. For example, for a wind speed of 15 mph, other things equal, PGW will increase the sendout by 5%. There is no adjustment factor for wind speed of below 10 mph.

[c] It is the design day sendouts of utilities, relative to the peak winter day of 65 heating degree days.

[d] Applies only to interstate supplies.

n/a = Data not available.

Findings:

- PGW's design day is *consistent with* other utilities' design day planning and 48-year historical peak winter.

Docket No. R-04XXX
Item 53.64 (c)(14)

Philadelphia Gas Works

Pennsylvania Public Utility Commission
52 Pa. Code §53.61, et seq.

Item 53.64(c) Thirty days prior to the filing of a tariff reflecting an increase or decrease in natural gas costs, each Section 1307(f) gas utility seeking recovery of purchased gas costs under that section shall provide notice to the public, under § 53.68 (relating to notice requirements), and shall file the following supporting information with the Commission, with a copy to the Consumer Advocate, Small Business Advocate and to intervenors upon request:

(14) Analysis and data demonstrating, on an historic and projected future basis, the minimum gas entitlements needed to provide reliable and uninterrupted service to priority one customers during peak periods.

Response:

In 1997, PGW contracted with ICF Kaiser Group to review its capacity entitlements. A copy of the final report is attached.

PGW Gas Supply Study
Final Report

Prepared for:

Philadelphia Gas Works

Prepared by:

ICF Kaiser International, Inc.

ICF KAISER

July 2, 1997

PGW Gas Supply Study
Final Report

Prepared for:

Philadelphia Gas Works

Prepared by:

ICF Kaiser International, Inc.

July 2, 1997

ICF KAISER

Outline of Report

- <u>**Purpose of Study**</u>
- **Overview of Assignment**
  - Management Review
  - Peak Day Study
  - Risk Management Study
  - LNG Liquefaction Options Study
  - Supply Optimization
- **Supply Study--Analytic Approach**
- **Findings**
- **Conclusions**

Purpose of Study

- Conduct a broad assessment of PGW's gas supply operations to answer the following questions.
  - Does the PGW gas purchasing function operate in a way to minimize gas costs?
  - Does PGW over-estimate its peak requirements, leading to over commitments in delivery capacity?
  - Would implementing a risk management program reduce PGWs' gas supply costs?

Purpose of Study (contd.)

- Develop an analytic framework for assessing whether and how PGW can manage its gas pipeline, storage, and peak shaving capacity to minimize gas supply costs.
  - Has PGW over committed to pipeline or storage capacity?
  - Where can capacity reductions be made to reduce cost while maintaining delivery reliability?
    - Pipeline capacity
    - Storage
    - Peak shaving
  - How much interruption of BPS and LBS should PGW accept?
  - Would dropping the South Jersey sale allow PGW to turn back pipeline capacity and reduce costs?
  - Is the current commitment to LNG capacity excessive?

Outline of Report

- Purpose of Study
- <u>Overview of Assignment</u>
  - Management Review
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  - Supply Optimization Study
- Supply Study--Analytic Approach
- Findings
- Conclusions

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Overview of Assignment

- ICF has conducted four related studies at PGW
  - A management review of the gas supply function
  - A review of PGW's approach to estimating peak day and peak season gas demand
  - An evaluation of a risk management strategy for PGW
  - A gas supply optimization study
- This report presents the final results of the gas supply optimization study
- In a related assignment, ICF Kaiser evaluated alternative approaches to upgrading the LNG liquefaction facilities at the Richmond plant

Management Review (Dec. 1996)

- Management recommendations were made for four areas
  - Gas Acquisition
  - Gas Control
  - Gas Planning
  - Regulatory Affairs
- Specific recommendations were made for aligning PGW's gas supply function with PGW's corporate strategy

Peak Day Study (Feb. 1997)

- Focused on estimations of design day, winter and year
- Concluded that PGW's approach yields reasonable results consistent with empirical data
- PGW's design weather estimates are not overly conservative
  - The design winter is less than the 48-year historical peak winter
  - The monthly design winter conditions are well below the 48-year peak
  - Design winter conditions lie within the 95 percent confidence interval
  - A winter as cold or colder than the design winter is likely to occur once in 16 years

Risk Management (Jan. 1997)

- The study made three findings
  - PGW and its customers have substantial exposure to market risks through the reliance on market pricing for gas supply
  - This exposure is mitigated partially by the investment in storage and LNG
  - Active risk management can further mitigate risk and provide opportunities to develop innovative products for PGW's customers
- The study recommended PGW proceed deliberately to develop a risk management function
  - PGW should use a phased approach to maximize learning about risk management
    - PGW should begin with a pilot project

LNG Liquefaction Options (June 1997)

- In a related report, ICF Kaiser in conjunction with CH-IV Corporation and MPR Engineers analyzed options for improving the 30 year old liquefaction facilities at Richmond
  - Upgrade the existing system and replace 30+ year old compressors with modern centrifugal compressors
  - Install an open expander system
  - Install a mixed refrigerant system
- New technologies can enhance reliability, provide operational flexibility, additional liquefaction capability, and reduced liquefaction costs

Outline of Report

- **Purpose of Study**
- **Overview of Assignment**
  - Management Review
  - Peak Day Study
  - Risk Management Study
  - LNG Liquefaction Options Study
  - Supply Optimization Study
- **<u>Supply Study--Analytic Approach</u>**
- **Findings**
- **Conclusions**

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Purpose of the Supply Optimization Study

- Develop an analytic framework for assessing whether and how PGW can manage its gas pipeline, storage, and peak shaving capacity to minimize gas supply costs.
  - Has PGW over committed to pipeline or storage capacity?
  - Where can capacity reductions be made to reduce cost while maintaining delivery reliability?
    - Pipeline capacity
    - Storage
    - Peak shaving
  - How much interruption of BPS and LBS should PGW accept?
  - Would dropping the South Jersey sale allow PGW to turn back pipeline capacity and reduce costs?
  - Is the current commitment to LNG capacity excessive?

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Analytic Approach - Optimization

- ICF Kaiser used the Gas Acquisition Strategy Model[2]
- GASM[2] optimizes across all supply and demand options
  - Pipeline capacity
  - Storage
  - Peak shaving -- LNG/Propane
  - Interruption
- The optimal solution identifies the least cost supply strategy under given assumptions
  - Multiple model runs test "What ifs"
  - Minimizes costs to PGW and customers

Analytic Approach - Optimization Inputs

- Define the period to be studied (multi-year or single year) and the detail within the period
- Provide gas requirements as load duration curve: total sendout or by customer class
- Identify and characterize gas supply options
- Identify and characterize the pipeline transportation options
- Identify and characterize storage and peak shaving options
- Integrate storage, transportation and peak capacities

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Analytic Approach - Period and Term

- The Study used a single year representation for PGW
  - PGW has no long-term contracts with distinctive pricing terms
  - Allows greater load detail for modeling critical winter months
- GASM^2 used 36 load periods per simulation
  - November through March (20 periods total)
    - 4 periods per month: Peak, Next 3 days, Next 10 days, Remainder of the month
  - April, May, September, October (12 periods total)
    - 3 periods per month: Peak, Next 13 days, Remainder of the month
  - June (2 periods)
    - 14 highest days, Remainder of the month
  - July, August (2 periods total)

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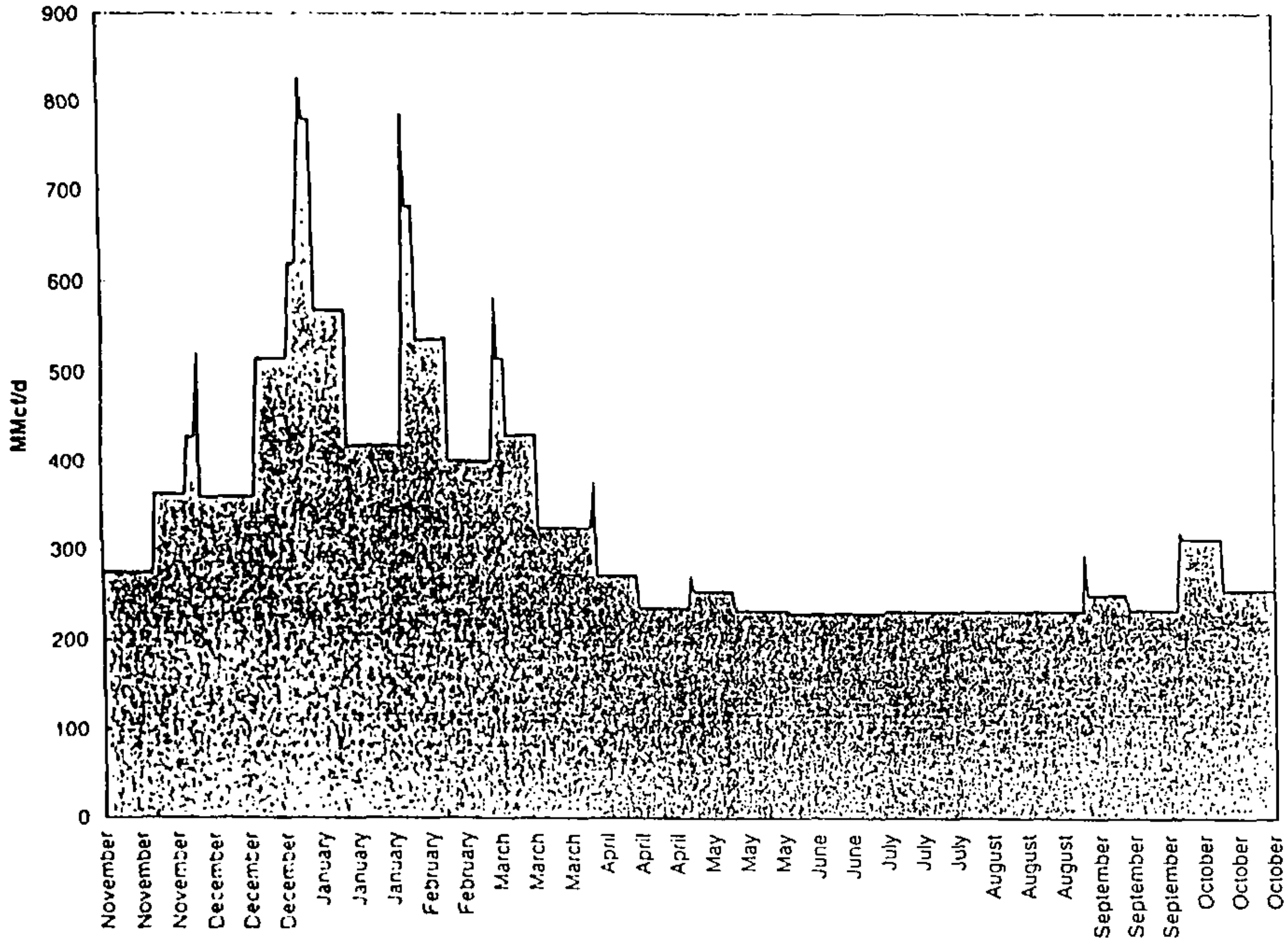
Analytic Approach - Load Characterization

- Used PGW's load forecasting DOM/HDD method by customer class
- Used design year definitions for HDD inputs
  - Increased firm demand in January to equal all-time peak month
- Customer classes grouped into six categories
  - Residential, Commercial, Industrial (firm), Interruptible (No. 6 fuel oil), Interruptible (No. 2 fuel oil), Municipal
  - Interruption occurs when cost of serving interruptible customer exceeds alternative fuel cost
- South Jersey sales incorporated separately
  - 10 days of 25 Mmcf/day on winter peaks.

(See Appendix A for key load inputs)

Analytic Approach - Chronological Load Duration Curve (includes storage injection)



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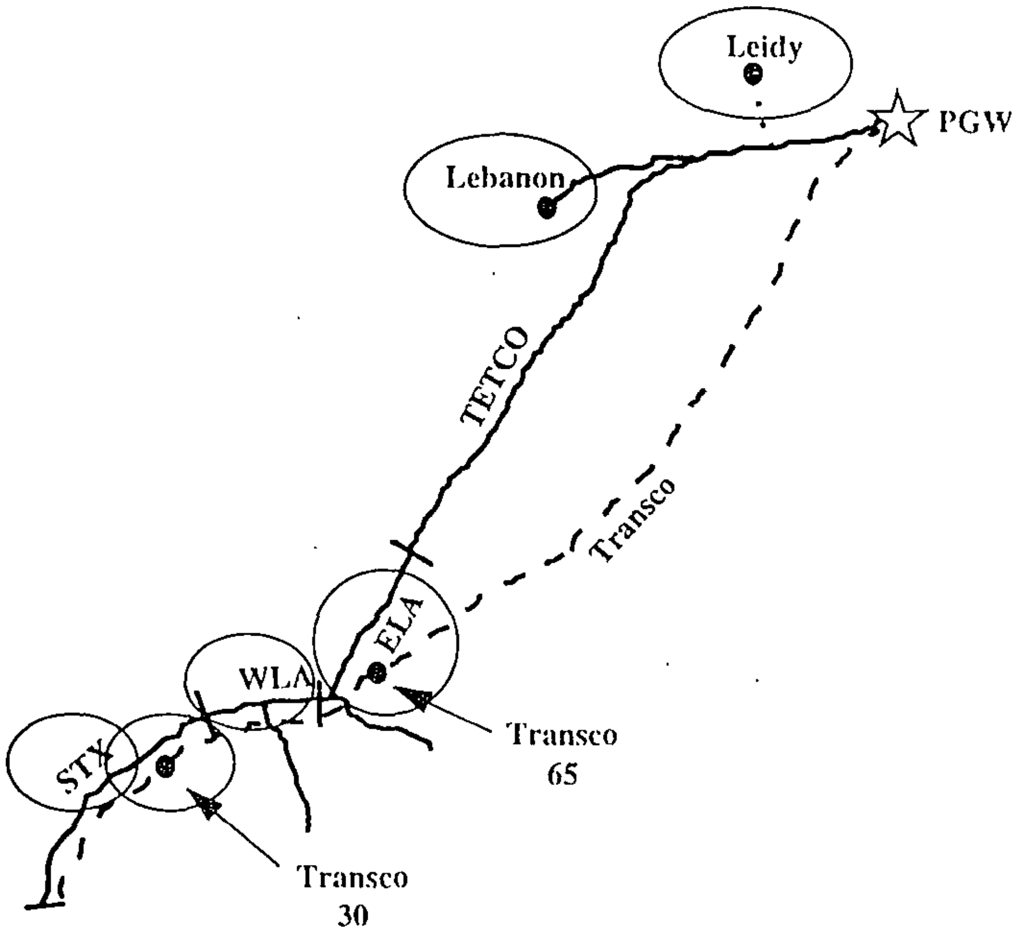
Analytic Approach - Gas Supply Markets



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Analytic Approach - Characterize Gas Supply Options

- Contract prices are assumed to be indexed to monthly spot prices ($/Mcf)
  - Average Price
  - Winter
  - Spring Fall
  - Summer
  - Prices used are from DRI Summer 1996 forecast
- Contract parameters include minimum take requirements and demand charges
- Spot supplies can provide no more than 30% of gas in base case

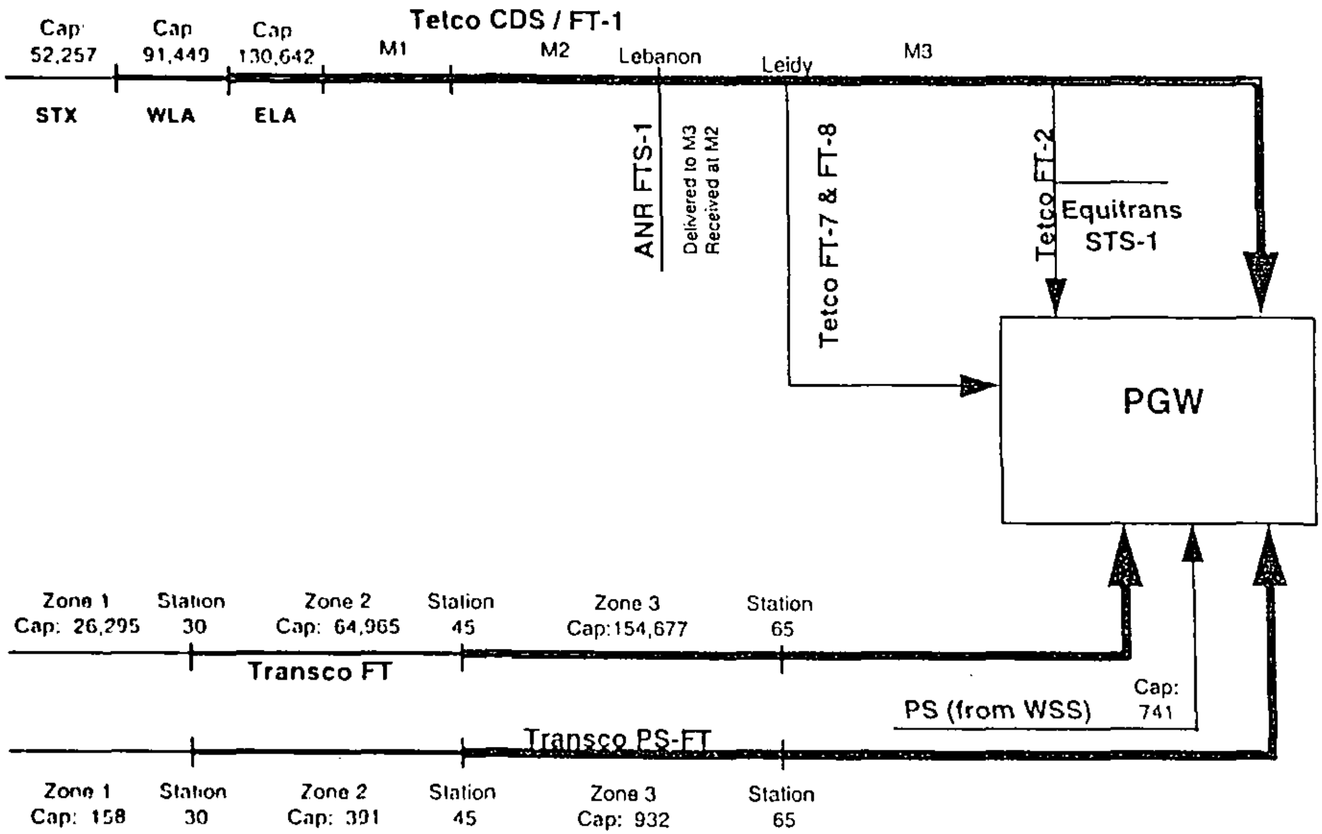
(See Appendix A for key supply inputs)

Analytic Approach - Characterize Pipeline Options

- Pipeline Name
  - Transco
  - Tetco
  - ANR
  - Equitrans
- Contract Type
- Capacity by Zone
- Expiration Date of Contract
- Distinguishing Operational Rules (i.e., winter only; tied to a given storage)

(See Appendix A for key pipeline inputs)

Analytic Approach - Characterize Pipeline Options (contd)



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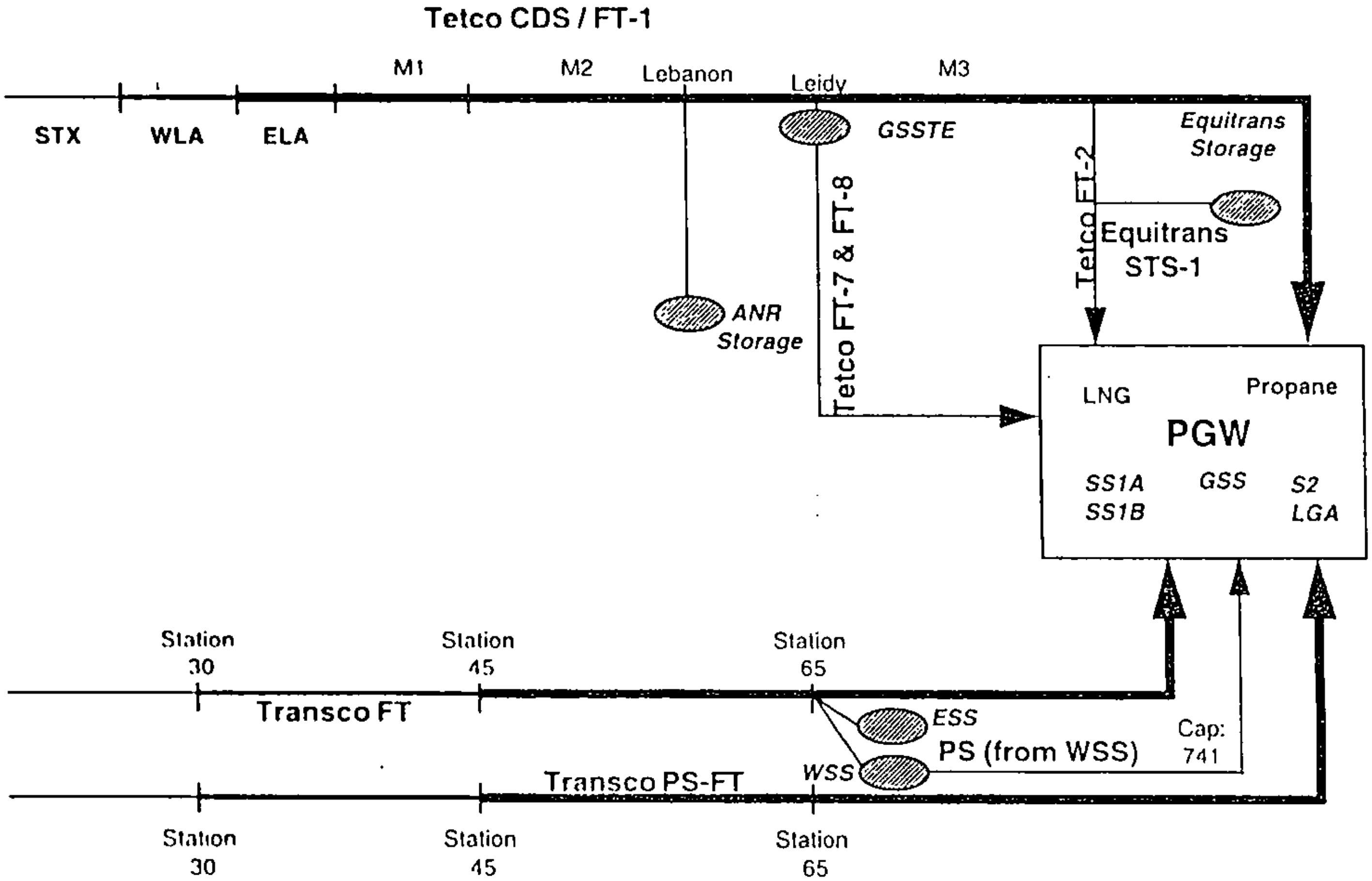
Analytic Approach - Storage and Peak Shaving Options

- Storage is matched with associated pipeline capacity
  - GSS (Transco), SS1A, SS1B, S2 and LGA storage assumed to be available at citygate
  - Equitrans and GSS (TETCO) storage associated with unbundled capacity to the city gate
  - WSS, ESS, and ANR storage treated as production area storage
- "Untouchable" gas under storage contracts is subtracted from available capacity
- LNG is assumed to have year-round minimum inventory of 750 MMcf
  - Maximum available for use equals 3,550 MMcf
- Propane is treated as a locally available, high-priced supply

(See Appendix A for key inputs)

Analytic Approach - Integration



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Outline of Report

- **Purpose of Study**
- **Overview of Assignment**
  - Management Review
  - Peak Day Study
  - Risk Management Study
  - LNG Liquefaction Options Study
  - Supply Optimization
- **Supply Study--Analytic Approach**
- **<u>Findings</u>**
- **Conclusions**

Findings - Three Sets of Cases Studied

- Three cases address the basic questions raised by PGW about the levels of capacity commitments
  - Base--current contract levels are fixed, approximates current operations
  - Open--all contracts can be modified; model is allowed to choose least cost mix of contract levels
  - Modified Open--only expiring contracts can be modified
- Two cases examine the implications of terminating the South Jersey contract
  - Base without South Jersey--base case with the South Jersey contract terminated
  - Modified Base without South Jersey--modified case after the South Jersey contract expires

Findings - Three Sets of Cases Studied (contd)

- Two cases examine the impact of turning back pipeline capacity if the South Jersey contract expires
  - 10,000 Mcf/d turn back
  - 20,000 Mcf/d turn back

Findings - Summary of Case Results

	Capacity Commitment			South Jersey			Turn Back		
	Base	Open	Modified ·Open	Base	Base No SJ	Modified Open No SJ	Base No SJ	Reduce Cap 10,000 Mcf/d No SJ	Reduce Cap 20,000 Mcf/d No SJ
Savings **($ Change from Base)**	-	6,202,600	682,200	-	(156,200)	573,000	(156,200)	(62,000)	(1,784,800)
Pipeline Load Factor **(%)**									
Winter	99%	98%	99%	99%	99%	99%	99%	99%	100%
Annual	81%	81%	81%	81%	81%	81%	81%	83%	85%
Storage **(% of Max Contract Cap)**									
Production	96%	63%	100%	96%	94%	100%	94%	99%	99%
Market	100%	98%	97%	100%	100%	97%	100%	100%	100%
LNG **(% of Max Contract Cap)**	100%	100%	100%	100%	100%	100%	100%	100%	100%
Interruption **(Days)**									
BPS	38	47	46	38	33	42	33	67	100
LBS	118	136	118	118	118	118	118	126	136
Propane **(Total MMcf Equivalent)**	0	0	0	0	0	0	0	0	16

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Findings - Eliminating the South Jersey Contract

- The expiration of the South Jersey contract would cost PGW approximately $150,000 relative to the base case
  - Contract elimination would allow PGW to reduce S-2 storage levels and BPS interruption
  - Resulting cost decreases would not offset the $1.25 million in lost revenue from South Jersey
- The expiration of the South Jersey contract would reduce the savings gained under the modified open case
  - Like above, there would be less interruption of BPS customers
- PGW's service to South Jersey contributes more than it costs

Findings - Capacity Turn Back

- Turning back 10,000 Mcf/d of TETCO CDS capacity would cost PGW and its customers over $60,000 per year
  - Interruption of BPS would double and LBS increase by 8 days
  - More expensive storage would have to be used
- Turning back 20,000 Mcf/d of pipeline capacity would be extremely costly
  - Costs would increase by almost $1.8 million
  - BPS customers would be interrupted 100 days and LBS customers for 136 days
  - This is the only case where PGW would have to use propane

Outline of Report

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- **<u>Conclusions</u>**

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Conclusions

- PGW has the right mix of pipeline capacity
  - Under all of the cases studied, the current levels of pipeline capacity were fully utilized in winter
  - Turn back of pipeline capacity would lead to higer costs by forcing the use of more expensive supply options and greater levels of interruption
- PGW's LNG capacity is fully utilized under all cases
  - LNG is an important element of PGW's capacity mix, providing peak day reliability and winter capacity at reasonable cost
  - LNG capacity in conjunction with pipeline capacity may provide greater opportunities for on-and off-system services

Conclusions (contd)

- PGW can reduce costs by eliminating several storage contracts--ANR, Eminence and Transco LGA and reduce its capacity under Transco S-2
  - Under the Open case, the optimal mix of supply could meet demand without using these services
- PGW can reduce costs, where the opportunity to reduce capacity commitments is limited to expiring contracts, by eliminating the LGA storage and cutting back S-2 storage
- PGW should not terminate the South Jersey contract
  - South Jersey contributes more than it costs to serve
  - Termination would not allow PGW to reduce pipeline capacity commitments and save money

Conclusions (contd)

- PGW's interruptible customers are on the margin in most cases
  - Reductions in capacity commitments increase the interruption of BPS and LBS customers
  - PGW should consider innovative Btu-services for these customers
- PGW should consider ways to maximize the value of existing assets by developing new services for on- and off-system customers
  - PGW should examine regional market opportunities for leveraging LNG and other assets
  - PGW should develop a capability to enhance offerings using risk management tools

Appendix A

Key Gas Supply Inputs

Market Location	Year	Average Price $/Mcf	Price Winter $/Mcf	Price Spring/Fall $/Mcf	Price Summer $/Mcf
Transco 30	1996-97	2.18	2.44	2.25	1.78
Transco 65	1996-97	2.23	2.49	2.30	1.83
Tetco South Texas (STX)	1996-97	2.05	2.24	2.11	1.74
Tetco Louisiana (ELA)	1996-97	2.21	2.48	2.27	1.81
Tetco Louisiana (WLA)	1996-97	2.21	2.48	2.27	1.81
CNG Leidy	1996-97	2.31	2.51	2.37	1.98
ANR Lebanon	1996-97	2.31	2.51	2.37	1.98

Key Load Inputs

Customer Class	Number of Customers	Peak Day Demand (MMcf)	Peak Month Demand (MMcf)	Annual Demand (MMcf)
Residential	500,655	589.7	11,255.4	56,304.9
Commercial	23,661	90.0	1,757.0	9,532.5
Industrial Firm	1,034	20.8	474.1	3,756.5
Municipal	742	20.2	377.1	1,722.3
Total Firm	***526,092***	***720.7***	***13,863.6***	***71,316.2***
Interruptible #2	410	48.5	1101.3	7,585.4
Interruptible #6	50	15.6	383.1	3,023.4
Total Interruptible	***460***	***64.1***	***1,484.1***	***10,608.8***
South Jersey	1	25.0	100.0	250.0
Grey's Ferry	1	0.0	0.0	8,388.0
Total Other	***2***	***25.0***	***100.0***	***8,638.0***
Total	**526,554**	**809.8**	**15,448.1**	**90,563.0**

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Key Pipeline Inputs

Company	Contract	Capacity	Expiration Date	Notes
Transco	FT	27,100 (Zone 1) 67,000 (Zone 2) 159,600 (Zone 3)	31-Mar-2005	
Transco	PS-FT	158 (Zone 1) 233 (Zone 2) 541 (Zone 3) 741 (Zone 4)	31-Jul-2011	Winter Only
TETCO	CDS	72,674	31-Oct-2003	
TETCO	FT-1	57,967	31-Oct-2003	
TETCO	FT-2	5,227	31-Mar-2002	Formerly bundled with Equitrans storage.
TETCO	FT-7	7,238	15-Apr-2006	Formerly bundled with CNG storage
TETCO	FT-8	24,905	31-Mar-2006	Formerly bundled with CNG storage.
ANR	FTS-1	13,168 (Summer) 9,329 (Winter)	31-Mar-2013	Delivers gas to TETCO at Lebanon.
Equitrans	STS-1	4,843	1-Apr-2002	Delivers gas to TETCO FT-2.

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Key Storage and Peak Shaving Inputs

Company	Contract	Expiration Date	Injection Period	Withdrawal Period	Storage Capacity	Max. Withdrawal Capacity	Ratchet	Injection Capacity	Notes:
Transco	WSS	31-Mar-1998	Year Round	Year Round	3,232,470	38,029	Y	15,105	
Transco	FSS	31-Oct-2013	Year Round	Year Round	79,700	10,230	N	682	Capacity will increase with expiration of Transco FS sales volumes.
Transco	S-2	11/15/1974*	4/16 - 11/15	11/16 - 4/15	452,087	5,032	N	2,324	Service may be canceled with 12 months prior notice.
Transco	GSS	Pending	Year Round	Year Round	3,893,346	59,658	Y	19,563	Storage capacity reduced 7% to account for base volumes. Monthly extraction 87.5% of daily total.
Transco	LGA	31-Oct-1991	4/1 - 10/31	11/1 - 3/31	50,848	10,171	N	254	
TETCO	SS-1A	30-Apr-2012	Year Round	Year Round	2,570,000	42,750	Y	13,184	Storage capacity reduced 4% to account for base volumes.
TETCO	SS-1B	30-Apr-2012	Year Round	Year Round	2,390,344	20,201	Y	12,264	Storage capacity reduced 4% to account for base volumes.
CNG	GSS	31-Mar-2006	Year Round	Year Round	3,531,631	32,991	Y	21,097	Storage capacity reduced 7% to account for base volumes. Monthly extraction 87.5% of daily total.
Equitrans	SS-3	1-Apr-2002	Year Round	Year Round	506,298	4,843	Y	2,529	Typical injection period is 4/1 - 10/31; withdrawal period is 11/1 - 3/31
ANR	FSS	1-Jan-2003	4/1 - 10/31	11/1 - 3/31	1,843,400	13,429	N	9,200	
LNG			4/1 - 10/31	11/1 - 3/31	3,985,000	450,000		23,500	All costs other than fuel assumed to be fixed

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Appendix B

Summary of Cases (Base/Scenarios)

- Case 1: Base - All contracts are considered fixed
- Case 2: Open - No contracts are considered fixed
- Case 3: Modified Open - Capacities on expiring contracts are variable
- Case 4: Base, No South Jersey
- Case 5: Modified Open, No South Jersey
- Case 6: Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey)
- Case 7: Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey)

Case summary outline (Case 1 Base)

- All contracts are considered fixed
  - Capacities and capacity charges cannot change
  - Fixed costs are sunk for decisionmaking purposes

Case 1 Base: Sources of Supply

- Purchases - Range (incl. pipeline fuel): 230-355 MMcf
- Production area storage (including ANR)
  - Transco storage (ESS and WSS) used at over 98% of capacity
  - ANR storage used at 90% capacity
  - Peak day withdrawal: 39 MMcf
- Market area storage
  - Maximum storage capacity except LGA (high variable cost)
  - Peak day withdrawal: 165 MMcf

Case 1 Base: Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 290 MMcf
- No propane is used
- Interruption
  - 2.96 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 38 days
  - LBS customers are interrupted for 118 days

Case 1 Base: Capacity Use

❖ Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	88%
TETCO FT-1	99%	80%
TETCO CDS	96%	67%

*Winter = Nov 1 - Mar 31

Case 1 Base: Capacity Use (cont.)

- Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**4,942**
Transco WSS	*3,233*	*3,187*
Transco ESS	*80*	*80*
ANR FSS	*1,843*	*1,675*
Market Area	**13,395**	**13,384**
Transco S2	*452*	*452*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*41*
TETCO SS1A	*2,570*	*2,570*
TETCO SS1B	*2,390*	*2,390*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

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Case summary outline (Case 2 Open)

- No contracts are considered fixed
  - All fixed costs are avoidable
  - Capacities represented in portfolio are available
    - In the "capacity store"

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Case 2 Open: Sources of Supply

- Purchases - Range (incl. pipeline fuel): 210-354 MMcf
- Production area storage (including ANR)
  - All available WSS capacity is purchased; no ANR or ESS
  - Peak day withdrawal: 24 MMcf
- Market area storage
  - Some reductions from base case
    - TETCO SS-1 and CNG are used at 95% capacity; S2 at 85%
    - LGA eliminated
  - Peak day withdrawal: 152 MMcf

Case 2 Open: Sources of Supply (cont.)

- LNG
  - Maximum available capacity is used
  - Maximum withdrawal: 301 MMcf
- No propane is used
- Interruption
  - 3.47 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 47 days
  - LBS customers are interrupted for 136 days

Case 2 Open: Capacity Use

❖ Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	78%
TETCO FT-1	90%	55%
TETCO CDS	97%	99%

*Winter = Nov 1 - Mar 31

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Case 2 Open: Capacity Use (cont.)

❖ Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**3,236**
Transco WSS	*3,233*	*3,233*
Transco ESS	*80*	*0*
ANR FSS	*1843*	*3*
Market Area	**13,395**	**13,078**
Transco S2	*452*	*381*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*0*
TETCO SS1A	*2,570*	*2,507*
TETCO SS1B	*2,390*	*2,277*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

Case summary outline (Case 3 Modified Open)

- Capacities on contracts that have or are about to expire are considered variable for decisionmaking purposes
  - Transco WSS storage
  - Transco S-2 storage
  - Transco GSS storage
  - Transco LGA storage

Case 3 Modified Open: Sources of Supply

- Purchases - Range (incl. pipeline fuel): 223-356 MMcf
- Production area storage (including ANR)
  - All production area storage is used to capacity
  - Peak day withdrawal: 38 MMcf
- Market area storage
  - Most storage used to full capacity
    - LGA is eliminated; S2 is used at 33% of contract maximum
  - Peak day withdrawal: 155 MMcf

Case 3 Modified Open: Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 300 MMcf
- No propane is used
- Interruption
  - 3.26 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 46 days
  - LBS customers are interrupted for 118 days

Case 3 Modified Open: Capacity Use

❖ Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	88%
TETCO FT-1	98%	77%
TETCO CDS	96%	67%

*Winter = Nov 1 - Mar 31

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Case 3 Modified Open: Capacity Use (cont.)

- Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**5,156**
Transco WSS	*3,233*	*3,233*
Transco ESS	*80*	*80*
ANR FSS	*1843*	*1,483*
Market Area	**13,395**	**13,041**
Transco S2	*452*	*150*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*0*
TETCO SS1A	*2,570*	*2,570*
TETCO SS1B	*2,390*	*2,390*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

Case summary outline (Case 4 Base, No South Jersey)

- All contracts are considered fixed
  - Capacities and capacity charges cannot change
  - Fixed costs are sunk for decisionmaking purposes
- PGW does not supply gas to South Jersey
  - 2,500 Mcf/d for 10 days
  - Contract expires winter 97-98

Case 4 Base, No South Jersey: Sources of Supply

- Purchases - Range (incl. pipeline fuel): 231-356 MMcf
- Production area storage (including ANR)
  - Similar to the base case, with a slight reduction in use of ANR
  - Peak day withdrawal: 38 MMcf
- Market area storage
  - Maximum storage capacity is used for all except LGA and Equitrans
  - Peak day withdrawal: 165 MMcf

Case 4 Base, No South Jersey: Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 313 MMcf
- No propane is used
- Interruption
  - 2.74 Bcf of demand total
  - On PGW peak day: 15.6 MMcf (LBS customers)
  - BPS customers are interrupted for 33 days
  - LBS customers are interrupted for 118 days

Case 4 Base, No South Jersey: Capacity Use

❖ Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	87%
TETCO FT-1	99%	81%
TETCO CDS	96%	66%

*Winter = Nov 1 - Mar 31

Case 5 Modified Open, No South Jersey: Sources of Supply

- Purchases - Range (incl. pipeline fuel): 223-356 MMcf
- Production area storage (including ANR) is virtually identical to Case 3
  - All production area storage is used to capacity
  - Peak day withdrawal: 38 MMcf
- Market area storage
  - Most storage used to full capacity
    - LGA is eliminated
    - S2 now used at 19% of contract maximum
  - Peak day withdrawal: 153 MMcf

Case 5 Modified Open, No South Jersey: Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 300 MMcf
- No propane is used
- Interruption
  - 3.10 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 42 days
  - LBS customers are interrupted for 118 days

Case 5 Modified Open, No South Jersey: Capacity Use

❖ Pipeline load factors are the same as Case 3

Pipeline	Winter	Total
Transco FT	100%	88%
TETCO FT-1	98%	77%
TETCO CDS	96%	67%

*Winter = Nov 1 - Mar 31

Case 5 Modified Open, No South Jersey: Capacity Use (cont.)

- Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**5,156**
Transco WSS	*3,233*	*3,233*
Transco ESS	*80*	*80*
ANR FSS	*1843*	*1,483*
Market Area	**13,395**	**12,975**
Transco S2	*452*	*84*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*0*
TETCO SS1A	*2,570*	*2,570*
TETCO SS1B	*2,390*	*2,390*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

Case summary outline (Case 6 Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey))

- Delivery capacity to PGW is reduced by 10,000 Mcf/d on TETCO CDS
- PGW does not supply gas to South Jersey
  - 25,000 Mcf/d for 10 days
  - Contract expires winter 97-98

Case 6 Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey): Sources of Supply

- Purchases - Range (incl. pipeline fuel): 231-345 MMcf
- Production area storage (including ANR)
  - ANR and ESS are used to full capacity
  - WSS is used at 99% capacity
  - Peak day withdrawal: 40 MMcf
- Market area storage
  - Maximum storage capacity is used for all except LGA
  - Peak day withdrawal: 165 MMcf

Case 6 Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey): Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 275 MMcf
- Propane is not used
- Interruption
  - 4.00 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 67 days
  - LBS customers are interrupted for 126 days

Case 6 Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey): Capacity Use

❖ Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	88%
TETCO FT-1	99%	79%
TETCO CDS	97%	71%

*Winter = Nov 1 - Mar 31

Case 6 Pipeline Capacity Turn Back 10,000 Mcf/d (No South Jersey): Capacity Use (cont.)

- Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**5,110**
Transco WSS	*3,233*	*3,187*
Transco ESS	*80*	*80*
ANR FSS	*1843*	*1,843*
Market Area	**13,395**	**13,384**
Transco S2	*452*	*452*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*41*
TETCO SS1A	*2,570*	*2,570*
TETCO SS1B	*2,390*	*2,390*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

Case summary outline (Case 7 Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey))

- Delivery capacity to PGW is reduced by 20,000 Mcf/d on TETCO CDS
- PGW does not supply gas to South Jersey
  - 25,000 Mcf/d for 10 days
  - Contract expires winter 97-98

Case 7 Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey): Sources of Supply

- Purchases - Range (incl. pipeline fuel): 226-334 MMcf
- Production area storage (including ANR)
  - ANR and ESS are used to full capacity
  - WSS is used at 99% capacity
  - Peak day withdrawal: 39 MMcf
- Market area storage
  - Maximum storage capacity is used for all except LGA
  - Peak day withdrawal: 165 MMcf

Case 7 Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey): Sources of Supply (cont.)

- LNG
  - All capacity is used
  - Maximum withdrawal: 283 MMcf
- Propane is used at maximum capacity (16 MMcf equivalent)
- Interruption
  - 5.08 Bcf of demand total
  - On PGW peak day: 64.1 MMcf (all BPS and LBS customers)
  - BPS customers are interrupted for 100 days
  - LBS customers are interrupted for 136 days

Case 7 Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey): Capacity Use

- Pipeline load factors

Pipeline	Winter	Total
Transco FT	100%	88%
TETCO FT-1	100%	80%
TETCO CDS	98%	77%

*Winter = Nov 1 - Mar 31

Case 7 Pipeline Capacity Turn Back 20,000 Mcf/d (No South Jersey): Capacity Use (cont.)

❖ Storage Capacity Use

Storage	Contract Max.	Capacity Use
Production Area	**5,156**	**5,110**
Transco WSS	*3,233*	*3,187*
Transco ESS	*80*	*80*
ANR FSS	*1843*	*1,843*
Market Area	**13,395**	**13,384**
Transco S2	*452*	*452*
Transco GSS	*3,893*	*3,893*
Transco LGA	*51*	*41*
TETCO SS1A	*2,570*	*2,570*
TETCO SS1B	*2,390*	*2,390*
CNG GSST	*3,532*	*3,532*
Equitrans SS3	*506*	*506*

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