Tab 10

Docket No. R-14XXX
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 the GCR calculation in its 1307f March 1 filing.

Tab 11

Docket No. R-14XXX
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 08-09 through FY 12-13.

There were not any gas interruptions during the period of FY 08-09 through FY 12-13.

3 DAY PEAK ANALYSIS

Winter		Average	Hi	Low	Total	Firm	Cogen	LBS	BPS	GTS	IT
2008 - 2009	Jan 15	21	28	15	516,111	460,730	54	854	8,570	4,480	41,423
2008 - 2009	Jan 16	15	22	10	574,126	516,475	31	858	9,197	4,556	43,009
2008 - 2009	Jan 17	24	34	16	534,063	481,924	5	696	8,263	4,767	38,408
2009 - 2010	Jan 29	23	27	19	516,629	449,555	27	711	4,966	11,524	49,846
2009 - 2010	Jan 30	20	22	17	543,835	478,094	0	613	5,092	11,846	48,189
2009 - 2010	Jan 31	29	36	22	478,187	413,488	12	645	4,920	11,806	47,315
2010 - 2011	Jan 22	23	26	20	547,522	484,164	0	533	4,006	3,271	55,547
2010 - 2011	Jan 23	22	28	13	549,808	483,809	26	602	4,232	3,292	57,848
2010 - 2011	Jan 24	27	35	15	515,963	449,536	51	559	4,228	3,562	58,028
2011 - 2012	Jan 3	24	32	17	466,478	403,819	44	197	1,140	3,364	57,914
2011 - 2012	Jan 4	31	38	21	450,472	388,053	43	188	1,069	3,749	57,371
2011 - 2012	Jan 5	38	42	34	377,446	320,686	45	178	936	3,873	51,728
2012 - 2013	Jan 23	21	24	19	542,095	474,746	40	78	235	3,499	63,496
2012 - 2013	Jan 24	23	28	19	520,871	454,814	40	79	225	3,697	62,016
2012 - 2013	Jan 25	23	31	20	532,130	467,509	41	79	224	3,645	60,632

Tab 12

Docket No. R-14XXX
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. Also attached are excerpts from the August, 2006 ICF International *Natural Gas Supply Study* which supports PGW's peak day methodology.

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 at or below 32 degrees Fahrenheit, excluding holidays and weekends. All interruptible transportation 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 winter of FY 06-07 through FY 12-13 which would reflect the most current consumption behaviors of its customers. This period yielded 97 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 a 77.6 % correlation between firm sendout and degree-days. The multiple regression correlation co-efficient, 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 20,069 MCF.

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 97 data points and there were 95 Degrees of Freedom.

Finally, based upon the models developed, it can be determined that the company's projected peak day sendout should be set at 673,531 MCF per day at 0 degree 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).

Winter 07-13 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)
Friday	12/8/2006	30	35	1,225	42,875	379,705	10,849	382,429	382,501	382,636
Wednesday	1/17/2007	30	35	1,225	42,875	370,772	10,593	382,429	382,501	382,636
Thursday	1/25/2007	25	40	1,600	64,000	406,749	10,169	430,946	432,077	432,081
Friday	1/26/2007	23	42	1,764	74,088	446,122	10,622	450,353	451,162	450,968
Monday	1/29/2007	26	39	1,521	59,319	404,015	10,359	421,243	422,375	422,469
Tuesday	1/30/2007	32	33	1,089	35,937	363,931	11,028	363,022	361,925	361,733
Wednesday	1/31/2007	28	37	1,369	50,653	370,862	10,023	401,836	402,651	402,852
Monday	2/5/2007	14	51	2,601	132,651	546,382	10,713	537,683	531,767	532,605
Tuesday	2/6/2007	18	47	2,209	103,823	507,463	10,797	498,870	497,008	496,740
Wednesday	2/7/2007	22	43	1,849	79,507	495,549	11,524	460,056	460,544	460,266
Thursday	2/8/2007	25	40	1,600	64,000	482,566	12,064	430,946	432,077	432,081
Friday	2/9/2007	29	36	1,296	46,656	434,461	12,068	392,132	392,630	392,824
Tuesday	2/13/2007	28	37	1,369	50,653	423,203	11,438	401,836	402,651	402,852
Wednesday	2/14/2007	24	41	1,681	68,921	474,230	11,567	440,649	441,673	441,577
Thursday	2/15/2007	21	44	1,936	85,184	500,200	11,368	469,760	469,820	469,480
Friday	2/16/2007	26	39	1,521	59,319	466,898	11,972	421,243	422,375	422,469
Friday	2/23/2007	31	34	1,156	39,304	379,220	11,154	372,726	372,266	372,276
Tuesday	3/6/2007	23	42	1,764	74,088	469,214	11,172	450,353	451,162	450,968
Wednesday	3/7/2007	24	41	1,681	68,921	453,835	11,069	440,649	441,673	441,577
Thursday	3/8/2007	30	35	1,225	42,875	407,781	11,651	382,429	382,501	382,636
Friday	3/16/2007	31	34	1,156	39,304	347,933	10,233	372,726	372,266	372,276
Wednesday	12/5/2007	30	35	1,225	42,875	361,414	10,326	382,429	382,501	382,636
Thursday	12/6/2007	31	34	1,156	39,304	369,844	10,878	372,726	372,266	372,276
Wednesday	1/2/2008	26	39	1,521	59,319	413,844	10,611	421,243	422,375	422,469
Thursday	1/3/2008	25	40	1,600	64,000	440,624	11,016	430,946	432,077	432,081
Wednesday	1/23/2008	32	33	1,089	35,937	325,432	9,862	363,022	361,925	361,733
Thursday	1/24/2008	28	37	1,369	50,653	379,113	10,246	401,836	402,651	402,852
Friday	1/25/2008	28	37	1,369	50,653	378,207	10,222	401,836	402,651	402,852
Monday	2/11/2008	23	42	1,764	74,088	467,873	11,140	450,353	451,162	450,968
Wednesday	2/20/2008	29	36	1,296	46,656	378,525	10,515	392,132	392,630	392,824
Thursday	2/21/2008	32	33	1,089	35,937	355,857	10,784	363,022	361,925	361,733
Thursday	2/28/2008	28	37	1,369	50,653	454,604	12,287	401,836	402,651	402,852
Monday	12/8/2008	31	34	1,156	39,304	377,137	11,092	372,726	372,266	372,276
Monday	12/22/2008	25	40	1,600	64,000	447,137	11,178	430,946	432,077	432,081
Wednesday	12/31/2008	29	36	1,296	46,656	374,949	10,415	392,132	392,630	392,824
Wednesday	1/14/2009	27	38	1,444	54,872	398,582	10,489	411,539	412,567	412,730
Thursday	1/15/2009	21	44	1,936	85,184	460,730	10,471	469,760	469,820	469,480
Friday	1/16/2009	15	50	2,500	125,000	516,475	10,330	527,980	523,237	523,657
Tuesday	1/20/2009	26	39	1,521	59,319	416,473	10,679	421,243	422,375	422,469
Wednesday	1/21/2009	27	38	1,444	54,872	438,203	11,532	411,539	412,567	412,730
Monday	1/26/2009	31	34	1,156	39,304	388,449	11,425	372,726	372,266	372,276
Tuesday	1/27/2009	31	34	1,156	39,304	375,153	11,034	372,726	372,266	372,276
Thursday	1/29/2009	32	33	1,089	35,937	358,115	10,852	363,022	361,925	361,733
Friday	1/30/2009	32	33	1,089	35,937	377,076	11,427	363,022	361,925	361,733
Wednesday	2/4/2009	26	39	1,521	59,319	395,771	10,148	421,243	422,375	422,469
Thursday	2/5/2009	22	43	1,849	79,507	454,626	10,573	460,056	460,544	460,266

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)
Friday	2/6/2009	31	34	1,156	39,304	384,803	11,318	372,726	372,266	372,276
Friday	2/20/2009	29	36	1,296	46,656	366,505	10,181	392,132	392,630	392,824
Monday	2/23/2009	29	36	1,296	46,656	377,612	10,489	392,132	392,630	392,824
Tuesday	2/24/2009	30	35	1,225	42,875	349,346	9,981	382,429	382,501	382,636
Monday	3/2/2009	19	46	2,116	97,336	440,702	9,580	489,166	488,052	487,706
Tuesday	3/3/2009	22	43	1,849	79,507	432,303	10,054	460,056	460,544	460,266
Wednesday	3/4/2009	27	38	1,444	54,872	361,842	9,522	411,539	412,567	412,730
Friday	12/11/2009	32	33	1,089	35,937	363,428	11,013	363,022	361,925	361,733
Thursday	12/17/2009	30	35	1,225	42,875	356,688	10,191	382,429	382,501	382,636
Friday	12/18/2009	31	34	1,156	39,304	354,884	10,438	372,726	372,266	372,276
Wednesday	12/23/2009	30	35	1,225	42,875	367,047	10,487	382,429	382,501	382,636
Tuesday	12/29/2009	25	40	1,600	64,000	420,824	10,521	430,946	432,077	432,081
Monday	1/4/2010	30	35	1,225	42,875	395,770	11,308	382,429	382,501	382,636
Tuesday	1/5/2010	32	33	1,089	35,937	375,718	11,385	363,022	361,925	361,733
Friday	1/8/2010	29	36	1,296	46,656	385,545	10,710	392,132	392,630	392,824
Monday	1/11/2010	32	33	1,089	35,937	380,493	11,530	363,022	361,925	361,733
Tuesday	1/12/2010	32	33	1,089	35,937	378,607	11,473	363,022	361,925	361,733
Thursday	1/28/2010	32	33	1,089	35,937	371,065	11,244	363,022	361,925	361,733
Friday	1/29/2010	23	42	1,764	74,088	449,243	10,696	450,353	451,162	450,968
Monday	2/8/2010	32	33	1,089	35,937	375,766	11,387	363,022	361,925	361,733
Friday	2/12/2010	32	33	1,089	35,937	345,617	10,473	363,022	361,925	361,733
Thursday	2/25/2010	32	33	1,089	35,937	357,730	10,840	363,022	361,925	361,733
Thursday	12/9/2010	32	33	1,089	35,937	371,337	11,253	363,022	361,925	361,733
Monday	12/13/2010	30	35	1,225	42,875	369,045	10,544	382,429	382,501	382,636
Tuesday	12/14/2010	27	38	1,444	54,872	424,487	11,171	411,539	412,567	412,730
Wednesday	12/15/2010	29	36	1,296	46,656	407,762	11,327	392,132	392,630	392,824
Thursday	12/16/2010	29	36	1,296	46,656	410,227	11,395	392,132	392,630	392,824
Monday	12/27/2010	29	36	1,296	46,656	414,781	11,522	392,132	392,630	392,824
Friday	1/7/2011	32	33	1,089	35,937	351,215	10,643	363,022	361,925	361,733
Monday	1/10/2011	31	34	1,156	39,304	395,659	11,637	372,726	372,266	372,276
Tuesday	1/11/2011	32	33	1,089	35,937	370,916	11,240	363,022	361,925	361,733
Wednesday	1/12/2011	29	36	1,296	46,656	400,559	11,127	392,132	392,630	392,824
Thursday	1/13/2011	27	38	1,444	54,872	412,360	10,852	411,539	412,567	412,730
Friday	1/14/2011	30	35	1,225	42,875	401,787	11,480	382,429	382,501	382,636
Friday	1/21/2011	25	40	1,600	64,000	403,219	10,080	430,946	432,077	432,081
Monday	1/24/2011	27	38	1,444	54,872	449,536	11,830	411,539	412,567	412,730
Monday	1/31/2011	32	33	1,089	35,937	360,472	10,923	363,022	361,925	361,733
Thursday	2/3/2011	31	34	1,156	39,304	376,480	11,073	372,726	372,266	372,276
Tuesday	2/8/2011	29	36	1,296	46,656	388,936	10,804	392,132	392,630	392,824
Wednesday	2/9/2011	31	34	1,156	39,304	392,112	11,533	372,726	372,266	372,276
Thursday	2/10/2011	27	38	1,444	54,872	401,423	10,564	411,539	412,567	412,730
Tuesday	2/22/2011	31	34	1,156	39,304	346,592	10,194	372,726	372,266	372,276
Tuesday	1/3/2012	24	41	1,681	68,921	403,819	9,849	440,649	441,673	441,577
Wednesday	1/4/2012	31	34	1,156	39,304	388,053	11,413	372,726	372,266	372,276
Friday	1/20/2012	32	33	1,089	35,937	336,109	10,185	363,022	361,925	361,733
Tuesday	1/22/2013	20	45	2,025	91,125	451,610	10,036	479,463	478,989	478,624
Wednesday	1/23/2013	21	44	1,936	85,184	474,746	10,790	469,760	469,820	469,480
Thursday	1/24/2013	23	42	1,764	74,088	454,814	10,829	450,353	451,162	450,968
Friday	1/25/2013	23	42	1,764	74,088	467,509	11,131	450,353	451,162	450,968
Friday	2/1/2013	28	37	1,369	50,653	393,108	10,625	401,836	402,651	402,852
Wednesday	2/20/2013	31	34	1,156	39,304	375,145	11,034	372,726	372,266	372,276
			65	4,225	274,625	404,337	10,865	673,531	639,997	663,634
			Count	97						

Firm Sendout Projection Based Data From 07-13
Data for Daily Temperatures <= 32 Degrees Fahrenheit

	R Squared	Change	Student's T	Degrees of Freedom	Critical Value	@ 97.5% Significant
	0.775617	0.775617	18.121355	95	2.04	Yes
	0.776250	0.000633	0.515581	94	2.04	No
	0.776269	0.000019	0.089688	93	2.04	No

Degrees of Freedom	95	94	93
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	673,531	Mcf
Linear Projection at 15 Degrees Fahrenheit	527,980	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) + (X1u2* X1u2 Coeff)*

*Cubic SO = Constant + (X * X Coeff) + (X1u2* X1u2 Coeff) + (X1u3 * X1u3 Coeff)*

Linear Regression Confidence Level Table

Count	Degree Days X	Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Ydc	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	sdyc	t*sdyc	Lower Acc Lower	Upper Acc Ydc + t*sdydc	"- 1 SD" Lower	"+ 1 SD" Ydc + sdydc	"- 2 SD" Lower	"+ 2 SD" Ydc + 2sdydc
1	33	363,931	363,022	909	826,054	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
2	33	325,432	363,022	(37,590)	1,412,996,221	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
3	33	355,857	363,022	(7,166)	51,346,268	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
4	33	358,115	363,022	(4,907)	24,081,541	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
5	33	377,076	363,022	14,054	197,506,634	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
6	33	363,428	363,022	406	164,597	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
7	33	375,718	363,022	12,696	161,180,934	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
8	33	380,493	363,022	17,471	305,225,546	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
9	33	378,607	363,022	15,585	242,883,041	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
10	33	371,065	363,022	8,043	64,685,109	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
11	33	375,766	363,022	12,744	162,402,026	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
12	33	345,617	363,022	(17,405)	302,944,282	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
13	33	357,730	363,022	(5,292)	28,008,383	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
14	33	371,337	363,022	8,314	69,129,635	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
15	33	351,215	363,022	(11,807)	139,404,352	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
16	33	370,916	363,022	7,893	62,305,369	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
17	33	360,472	363,022	(2,550)	6,502,080	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
18	33	336,109	363,022	(26,913)	724,336,100	(4)	18	3,152	6,420	356,602	369,443	341,809	384,236	320,595	405,450
19	34	379,220	372,726	6,495	42,181,057	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
20	34	347,933	372,726	(24,793)	614,680,838	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
21	34	369,844	372,726	(2,882)	8,305,607	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
22	34	377,137	372,726	4,411	19,459,706	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
23	34	388,449	372,726	15,723	247,222,656	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
24	34	375,153	372,726	2,427	5,891,861	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
25	34	384,803	372,726	12,077	145,861,554	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
26	34	354,884	372,726	(17,842)	318,325,699	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
27	34	395,659	372,726	22,934	525,949,738	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
28	34	376,480	372,726	3,755	14,098,560	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
29	34	392,112	372,726	19,386	375,833,149	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
30	34	346,592	372,726	(26,133)	682,945,311	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
31	34	388,053	372,726	15,327	234,928,527	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
32	34	375,145	372,726	2,419	5,853,088	(3)	11	2,789	5,682	367,044	378,407	351,512	393,939	330,298	415,153
33	35	379,705	382,429	(2,724)	7,418,430	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
34	35	370,772	382,429	(11,657)	135,891,108	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
35	35	407,781	382,429	25,352	642,735,659	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
36	35	361,414	382,429	(21,015)	441,622,323	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
37	35	349,346	382,429	(33,083)	1,094,489,783	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
38	35	356,688	382,429	(25,741)	662,602,889	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
39	35	367,047	382,429	(15,382)	236,608,200	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
40	35	395,770	382,429	13,341	177,980,307	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
41	35	369,045	382,429	(13,384)	179,144,833	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
42	35	401,787	382,429	19,358	374,733,324	(2)	5	2,490	5,071	377,358	387,500	361,215	403,643	340,002	424,856
43	36	434,461	392,132	42,329	1,791,711,265	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
44	36	378,525	392,132	(13,608)	185,173,260	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
45	36	374,949	392,132	(17,183)	295,271,422	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
46	36	366,505	392,132	(25,627)	656,766,892	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
47	36	377,612	392,132	(14,520)	210,843,864	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
48	36	385,545	392,132	(6,587)	43,394,677	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
49	36	407,762	392,132	15,630	244,282,697	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
50	36	410,227	392,132	18,094	327,408,482	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
51	36	414,781	392,132	22,649	512,957,109	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560

Count	Degree Days X	Firm Sendout (Mcf) Y	Projected Linear Firm Sendout (Mcf) Ydc	Difference Actual Versus Projected Y - Yc	Actual Versus Projected Squared $(Y - Yc)^2$	(Degree Days - Xm) X - Xm	(Degree Days - Xm) Squared $(X - Xm)^2$	sdyc	t*sdyc	Lower Acc Lower	Upper Acc Ydc + t*sdydc	"- 1 SD" Lower	"+ 1 SD" Ydc + sdydc	"- 2 SD" Lower	"+ 2 SD" Ydc + 2sdydc
52	36	400,559	392,132	8,427	71,013,682	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
53	36	388,936	392,132	(3,197)	10,220,165	(1)	2	2,278	4,641	387,492	396,773	370,919	413,346	349,705	434,560
54	37	370,862	401,836	(30,974)	959,372,833	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
55	37	423,203	401,836	21,368	456,573,559	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
56	37	379,113	401,836	(22,723)	516,321,657	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
57	37	378,207	401,836	(23,629)	558,332,848	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
58	37	454,604	401,836	52,768	2,784,477,307	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
59	37	393,108	401,836	(8,728)	76,175,423	(0)	0	2,181	4,442	397,394	406,278	380,622	423,050	359,409	444,263
60	38	398,582	411,539	(12,957)	167,890,145	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
61	38	438,203	411,539	26,664	710,955,940	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
62	38	361,842	411,539	(49,697)	2,469,815,957	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
63	38	424,487	411,539	12,947	167,635,359	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
64	38	412,360	411,539	821	674,253	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
65	38	449,536	411,539	37,997	1,443,780,408	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
66	38	401,423	411,539	(10,116)	102,342,527	1	1	2,212	4,507	407,033	416,046	390,326	432,753	369,112	453,967
67	39	404,015	421,243	(17,227)	296,777,749	2	3	2,368	4,823	416,419	426,066	400,029	442,456	378,815	463,670
68	39	466,898	421,243	45,656	2,084,455,840	2	3	2,368	4,823	416,419	426,066	400,029	442,456	378,815	463,670
69	39	413,844	421,243	(7,399)	54,745,124	2	3	2,368	4,823	416,419	426,066	400,029	442,456	378,815	463,670
70	39	416,473	421,243	(4,770)	22,749,395	2	3	2,368	4,823	416,419	426,066	400,029	442,456	378,815	463,670
71	39	395,771	421,243	(25,472)	648,804,068	2	3	2,368	4,823	416,419	426,066	400,029	442,456	378,815	463,670
72	40	406,749	430,946	(24,197)	585,517,541	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
73	40	482,566	430,946	51,620	2,664,633,636	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
74	40	440,624	430,946	9,678	93,664,519	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
75	40	447,137	430,946	16,191	262,147,760	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
76	40	420,824	430,946	(10,122)	102,455,335	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
77	40	403,219	430,946	(27,727)	768,798,402	3	8	2,625	5,348	425,598	436,294	409,732	452,160	388,519	473,373
78	41	474,230	440,649	33,580	1,127,633,276	4	14	2,958	6,026	434,623	446,676	419,436	461,863	398,222	483,077
79	41	453,835	440,649	13,186	173,868,564	4	14	2,958	6,026	434,623	446,676	419,436	461,863	398,222	483,077
80	41	403,819	440,649	(36,830)	1,356,477,650	4	14	2,958	6,026	434,623	446,676	419,436	461,863	398,222	483,077
81	42	446,122	450,353	(4,231)	17,901,887	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
82	42	469,214	450,353	18,861	355,740,228	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
83	42	467,873	450,353	17,520	306,957,507	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
84	42	449,243	450,353	(1,110)	1,231,660	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
85	42	454,814	450,353	4,461	19,902,291	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
86	42	467,509	450,353	17,156	294,335,143	5	22	3,344	6,812	443,540	457,165	429,139	471,566	407,925	492,780
87	43	495,549	460,056	35,493	1,259,774,440	6	33	3,767	7,673	452,383	467,730	438,843	481,270	417,629	502,483
88	43	454,626	460,056	(5,430)	29,486,977	6	33	3,767	7,673	452,383	467,730	438,843	481,270	417,629	502,483
89	43	432,303	460,056	(27,753)	770,239,625	6	33	3,767	7,673	452,383	467,730	438,843	481,270	417,629	502,483
90	44	500,200	469,760	30,440	926,603,657	7	45	4,216	8,587	461,173	478,346	448,546	490,973	427,332	512,187
91	44	460,730	469,760	(9,030)	81,533,332	7	45	4,216	8,587	461,173	478,346	448,546	490,973	427,332	512,187
92	44	474,746	469,760	4,986	24,864,375	7	45	4,216	8,587	461,173	478,346	448,546	490,973	427,332	512,187
93	45	451,610	479,463	(27,853)	775,787,971	8	60	4,682	9,538	469,925	489,001	458,249	500,677	437,036	521,890
94	46	440,702	489,166	(48,464)	2,348,794,215	9	76	5,162	10,516	478,651	499,682	467,953	510,380	446,739	531,594
95	47	507,463	498,870	8,593	73,845,789	10	95	5,652	11,514	487,356	510,383	477,656	520,083	456,442	541,297
96	50	516,475	527,980	(11,505)	132,363,159	13	162	7,162	14,588	513,392	542,568	506,766	549,194	485,553	570,407
97	51	546,382	537,683	8,699	75,669,332	14	189	7,674	15,631	522,053	553,314	516,470	558,897	495,256	580,111
	65		673,531	(673,531)	453,643,689,821	28	770	15,014	30,582	642,949	704,113	652,317	694,744	631,103	715,958
Tot/Avg	37	404,337	404,337		43,651,844,559		1,603								

t = 2.04

Xm =	37			
Population Variance=	**450,019,016**			
			Upper Range	Lower Range
Population Standard Deviation of Regression =	21,214	1s	425,550	383,123
		2s	446,764	361,909

Standard error of sendout projection	21,436
T-factor	2.04
(T factor) * (Std error of projection)	43,663

Regression Results

Winter 07-13

Based On Data for Daily Temperatures <= 32 Degrees Fahrenheit

Regression Output:

Regression Output:		
Constant		42,810
Std Err of Y Est		20,069
R Squared		0.7756
No. of Observations		97
Degrees of Freedom		95
X Coefficient(s)	9,703	
Std Err of Coef.	535	
Zero Degree Temp Sendout		673,531
DD	65	

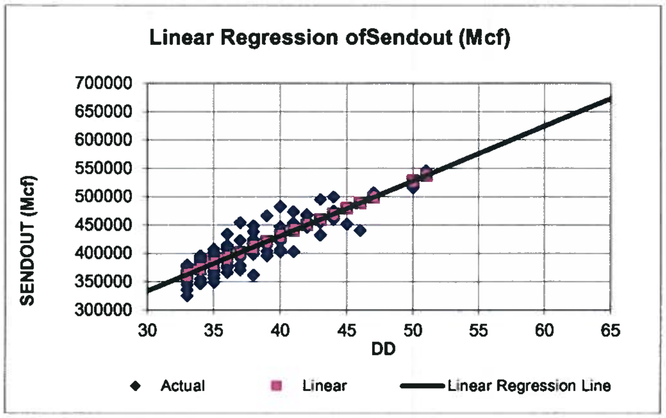
Quadratic

Regression Output:		
Constant		(39,127)
Std Err of Y Est		160,194
R Squared		1
No. of Observations		97
Degrees of Freedom		94
	X	X^2
X Coefficient(s)	13911.3738	(53)
Std Err of Coef.	8179.3260	103
		639,997

Cubic

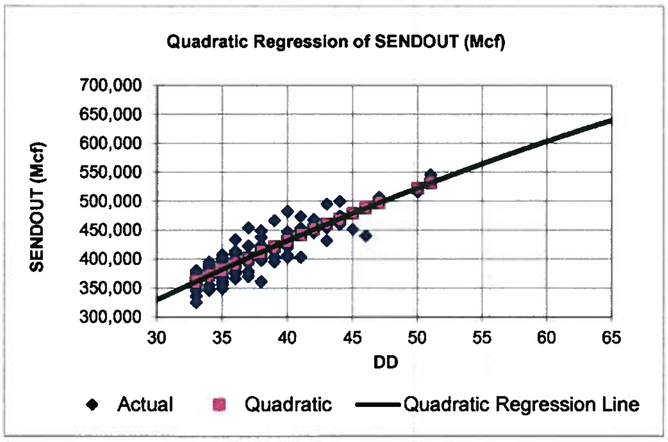
Regression Output:			
Constant		(161,792)	
Std Err of Y Est		1,377,136	
R Squared		1	
No. of Observations		97	
Degrees of Freedom		93	
	X	X^2	X^3
X Coefficient(s)	23,114	(281)	2
Std Err of Coef.	102,934	2,541	21
		663,634	

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 07-13



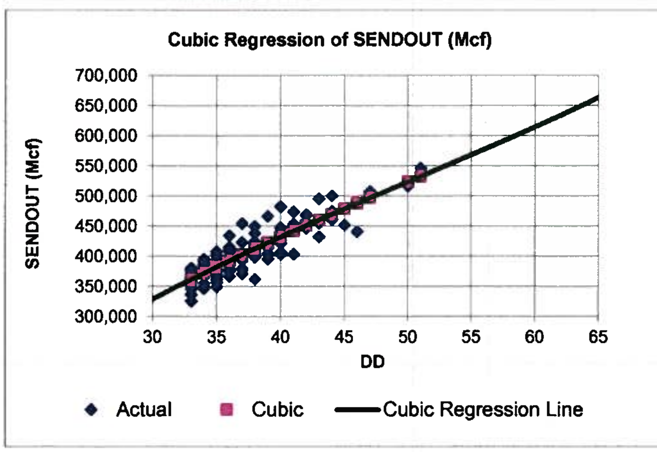
Linear Regression Output

Constant		42,810
Std. Error of Y Estimate		20,069
R Squared		0.776
Number of Observations		97
Degrees of Freedom		95
	X	
X Coefficient	9703	
Std. Err. Of Coefficeint	535	



Quadratic Regression Output

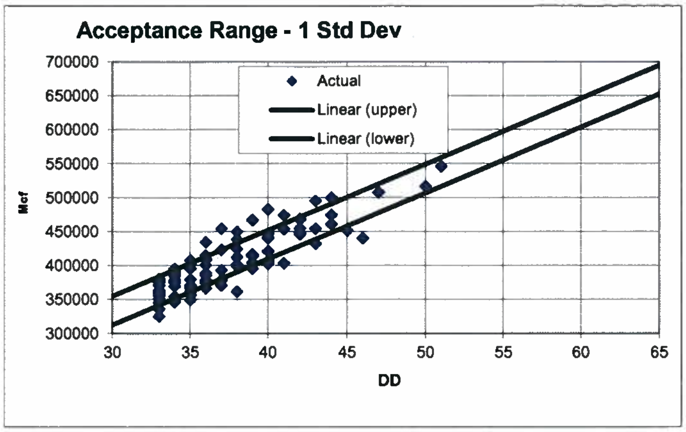
Constant		(39,127)
Std. Error of Y Estimate		160,194
R Squared		0.776
Number of Observations		97
Degrees of Freedom		94
	X	**X ^ 2**
X Coefficient	13,911	(53)
Std. Err. Of Coefficeint	8,179	103



Cubic Regression Output

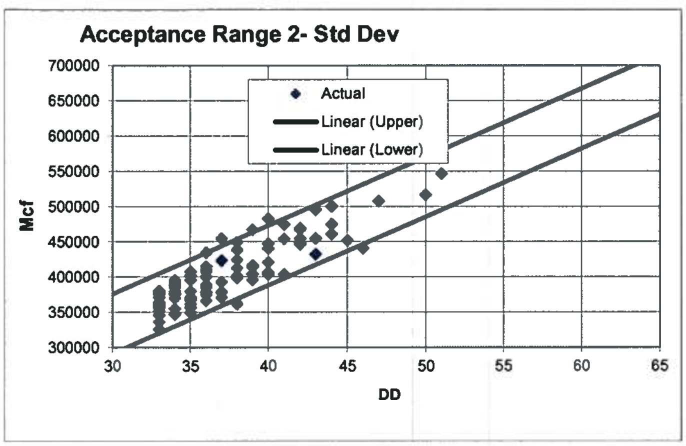
Constant		(161,792)	
Std. Error of Y Estimate		1,377,136	
R Squared		0.776	
Number of Observations		97	
Degrees of Freedom		93	
	X	**X ^ 2**	**X ^ 3**
X Coefficient	23114	(281)	2
Std. Err. Of Coefficeint	102934	2541	21

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 07-13



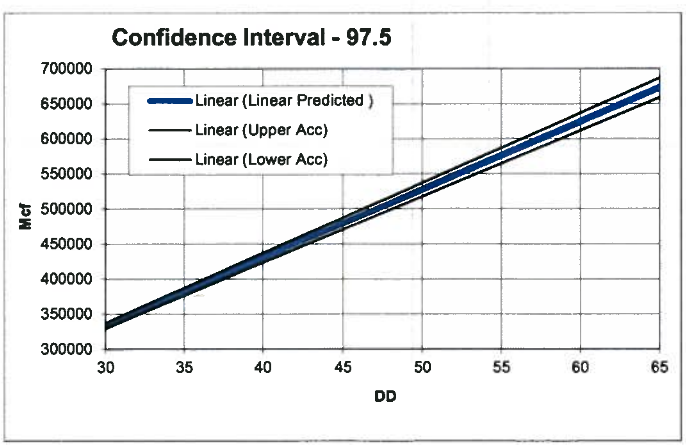
Acceptance Range @ 1 Standard Deviation

Regression Squared	450,019,016
Regression	21,214
Upper Range 1sd	425,550
Lower Range 1sd	383,123



Acceptance Range @ 2 Standard Deviation

Regression Squared	450,019,016
Regression	21,214
Upper Range 2sd	446,764
Lower Range 2sd	361,909



Confidence Interval: 97.5%

Regression Squared	450,019,016
Standard error of sendout projection	21,436
X Mean	37
T Distribution	2.04

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PGW Natural Gas Supply Study

**Prepared for
Philadelphia Gas Works**

PGW

August 2006

Outline

- Introduction
- Market Context
- Design Winter and Day Analysis
- Supply Analysis and Issues
- Conclusions and Recommendations

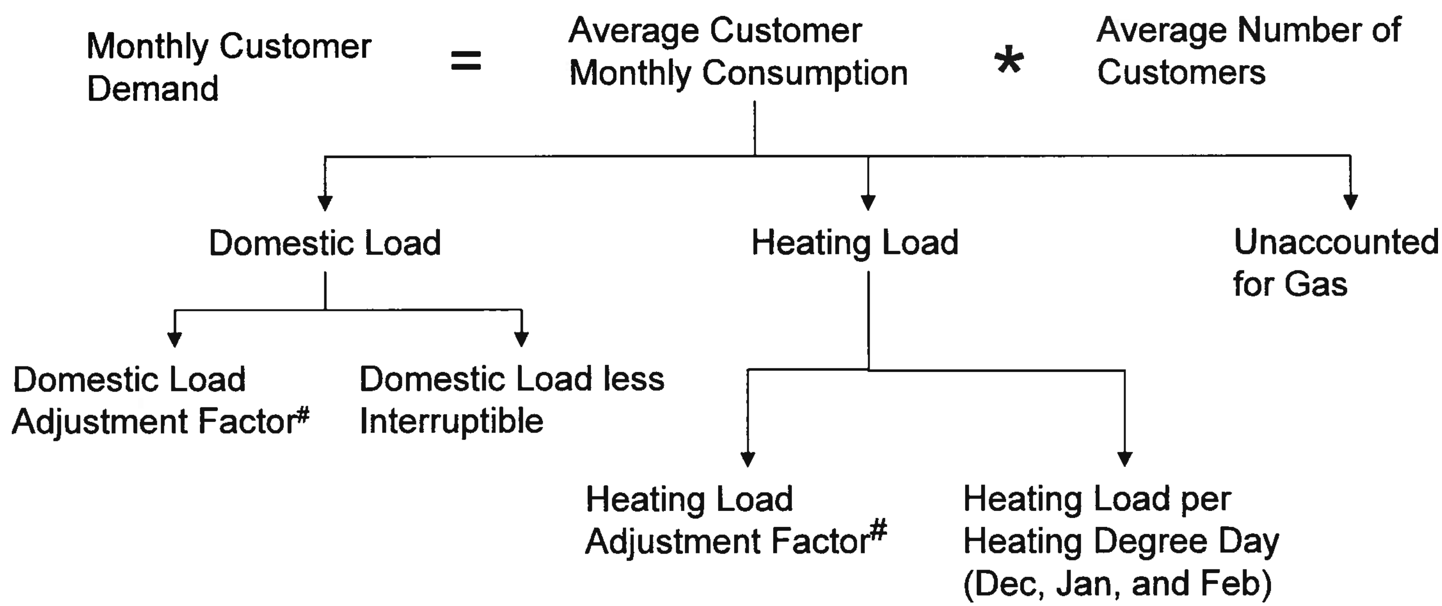
Purpose of Demand Estimation Review

- Design day and winter parameters drive investment decisions and asset allocations
  - Pipeline capacity
  - Storage capacity and utilization
  - LNG storage and vaporization
- Design parameters in turn impact system costs
  - Capacity payments
  - Inventory holding costs
- ICF used design day and design winter estimates to determine the appropriate gas asset mix

PGW's Approach to Estimating Demand

- PGW uses a combination of inputs into demand estimation
  - Historical demand trends for each customer class
  - Customer surveys
  - End use studies – appliance characteristics
  - Judgment of system operators
- Demand is related to temperature through heating degree days (HDD)
- Capacity planning focuses on the "Design Winter" and "Design Day"
  - These are concepts of peak demand that define the largest amount of gas that PGW must be able to deliver to meet system requirements and maintain system integrity
  - These represent statistically derived historical system peak limits

PGW Demand Estimation Methodology Overview



#Adjustment Factors account for error in estimation of demand in previous year

PGW Demand Estimation Methodology Evaluation

- Domestic Load is estimated by using latest year customer load thus accounting for improvements in energy efficiency of customer appliances
- Heating Load Adjustment Factor is estimated using normalized Heating Degree Days thus representing only error in estimation methodology
- Design Day demand estimated using firm load thus making the forecasting regression methodology robust
- Design Day demand estimated using four year peak day heating degree days allowing for a good fit

Philadelphia Winter Heating Degree Days

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Data Set (1976-2005)	Nov	Dec	Jan	Feb	Mar	Winter Season
Historical Mean Degree Days	533	862	1,028	844	671	3,938[b]
Historical Peak Degree Days	762	1,219	1,400	1,183	911	4,535[b]
No. of Sample Observations	30	30	30	30	30	30
Sample Standard Deviation	95	144	162	129	99	213
Data Relative to Mean[a] (%)	18	17	16	15	15	5[b]
PGW's Design Degree Days	608	1,005	1,191	973	778	4,555

Notes:

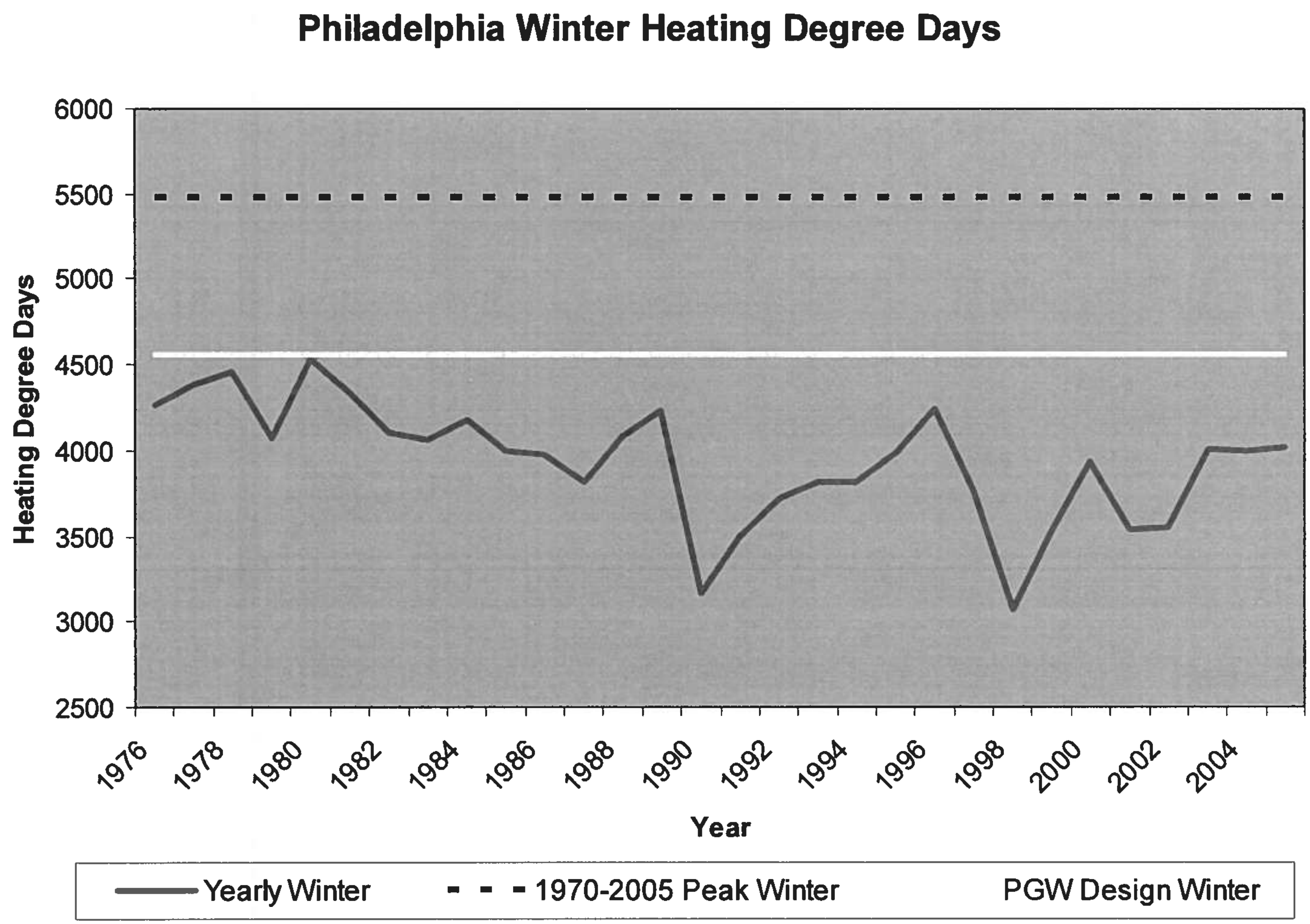
[a] It is coefficient of variation, calculated as (sample standard deviation/sample mean)*100.

[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.

PGW Design Degree Days are higher than NOAA estimate because of the location and frequency of measurements. PGW measures several times per day at the Richmond Plant. NOAA uses a simple average of the high and low temperatures.

Passion. **Expertise. Results.**

PGW Design Winter Heating Degree Days



Passion. Expertise. Results.

PGW's Design Year Estimates

- The previous slide compares the design winter based on coldest winter in 30 years with historical winter weather and the theoretically coldest winter, measured in heating degree days (HDDs).
- Recent winters have been warmer than in the 1980s, and the trend suggests warming.
- PGW's design winter is still substantially below the theoretical coldest winter
  - Theoretical coldest winter includes the coldest winter months picked from the last 30 years and assumes each month is the thirty year cold month

Findings on Peak and Winter Demand

- PGW's approach remains essentially the same as was reviewed in the previous study.
- PGW's approach yields a forecast of design day and design winter that are reasonable estimations.
  - The design conditions are below "theoretical" worst case (which could yield higher than necessary investments)
  - The probability of meeting design winter conditions remains approximately once in every 16 years.
- PGW's approach incorporates recent trends in local markets towards more efficient equipment and demand response to prices.
- Potential for demand growth is modest (given local and national trends).

ICF's Approach to Estimating Design Winter Sendout

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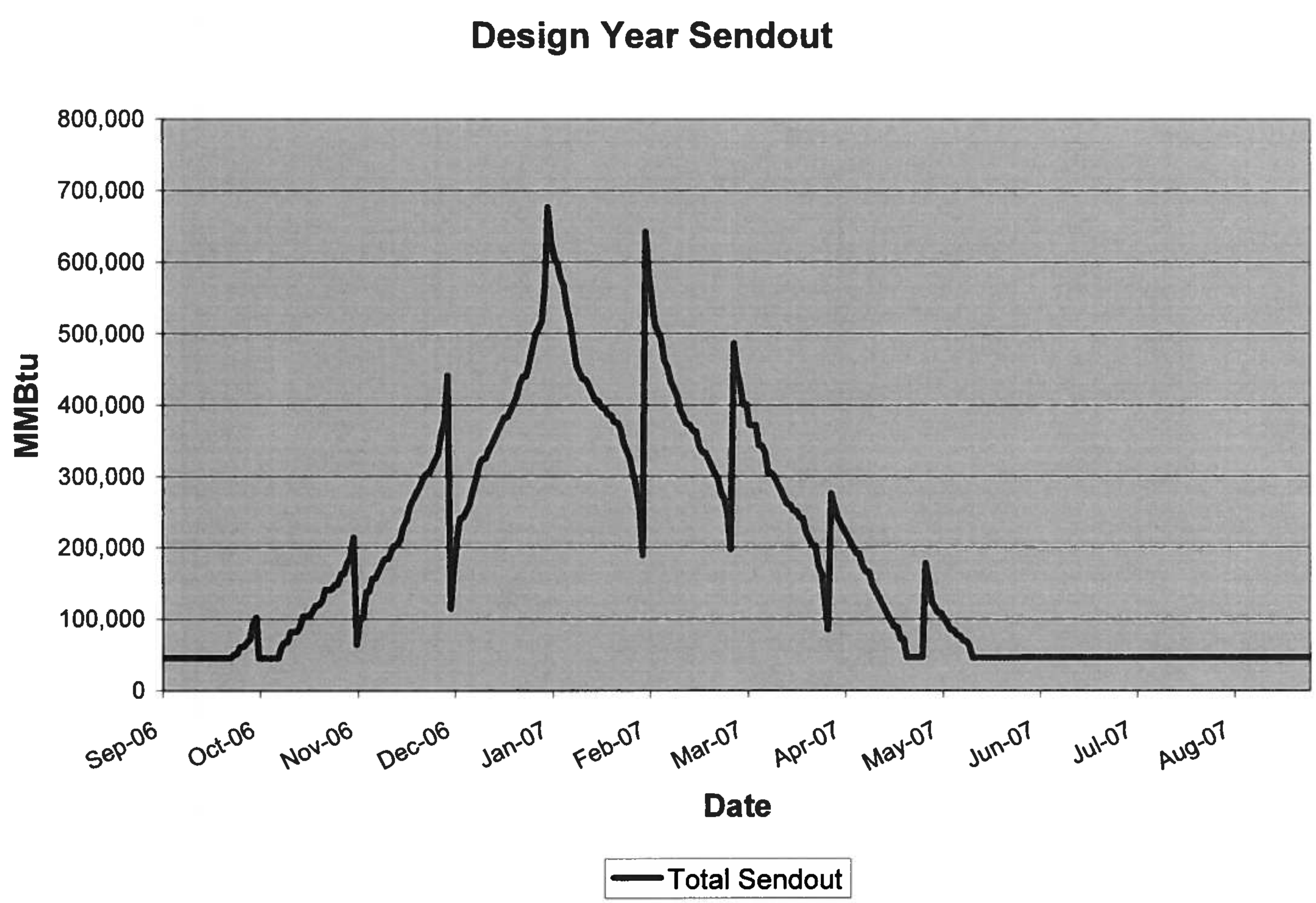
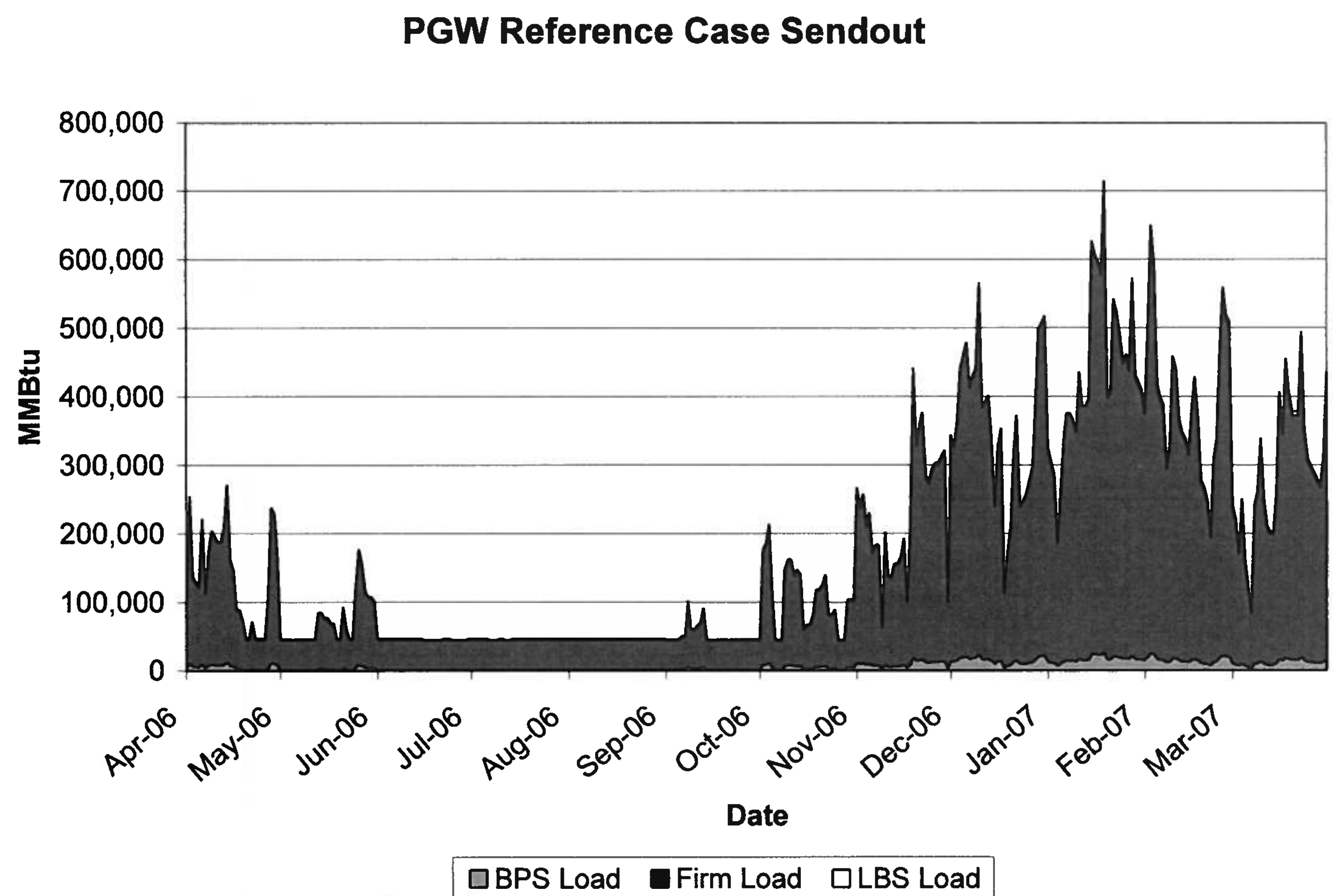
- First step is to use design winter parameters for 2006-2007 provided by PGW for its PGC filings with the Philadelphia Gas Commission.
  - These data are from September through August and in the form of load duration curves for each month.
- Data were converted to April through March and randomized to reflect typical random weather and gas pricing patterns.
  - Converting data for April through March makes modeling storage easier
  - Gas sendout and prices are correlated
- Design and average years were differentiated.
  - All the analysis is based on daily, sequential sendout
  - Average and design years differ only in winter sendout

Design Year Sendout for Planning – Sept. 1 to August 31

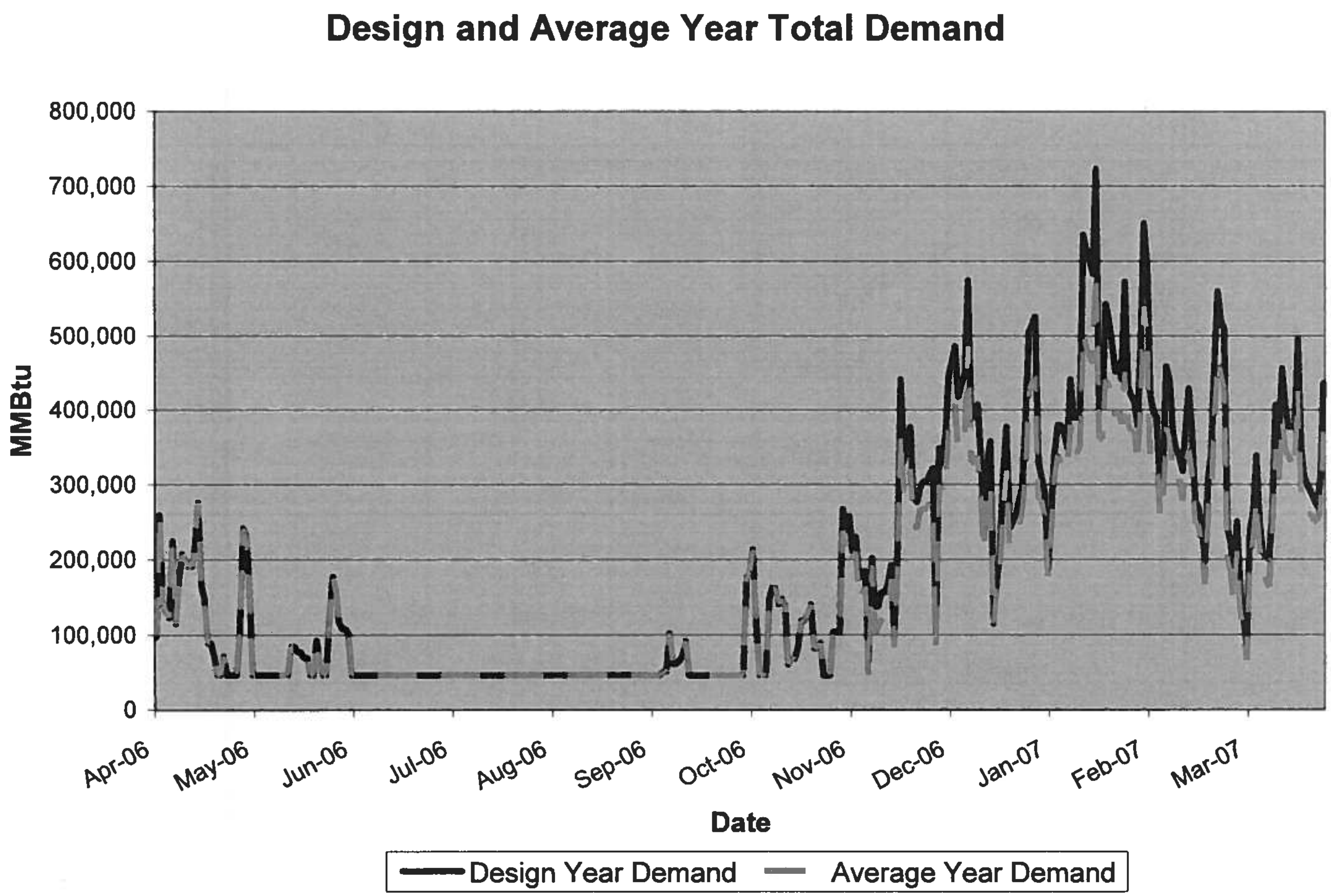


Passion. **Expertise. Results.**

Sendout Reordered and Randomized – April 1 to March 31



Demand Patterns Modeled Consistent with Gas Prices



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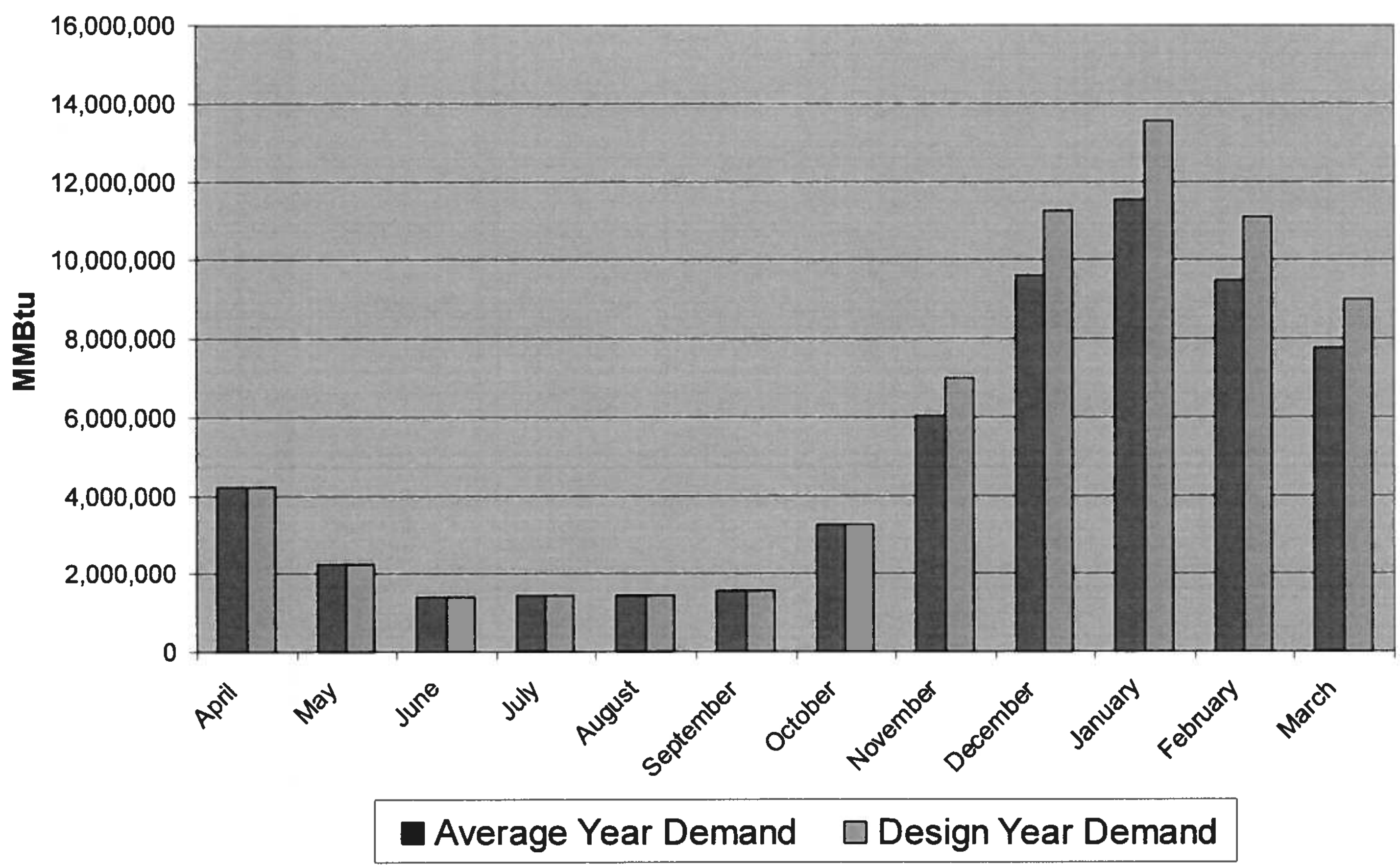
Design and Average Winter Demand -- Simplified

Design and Average Year Total Demand



Observation: Design Day Deliverability is an Incomplete Measure of Asset Value

ICF INTERNATIONAL

- Comparing Design Day requirements with available options is not a complete analysis.
- PGW operates with a 12 percent reserve margin over Design Day sendout requirements. This does not appear unreasonable.
  - Deliverability options on Design Day include
    - Transco long haul pipeline capacity
    - Transco GSS storage
    - Tetco/Dominion/Equitrans Storage delivered through Tetco FTS services
    - LNG
    - PAID – released capacity which has no long term fixed costs
- Design Day does not account for "Design Hour" requirements to maintain system pressures
- Design Day does not account for storage optionality in volatile gas markets.

Conclusions and Recommendations

- PGW's approach to estimating design winter and day conditions is reasonable and yields results that are prudent for capacity planning purposes.
- PGW uses its full pipeline capacity during winter seasons. Overall capacity utilization is higher for Transco, which is the lower cost pipeline, than it is for Tetco.
  - PGW has some opportunities to release capacity on these pipes, or engage in off-system sales when capacity is not needed for native load.
  - PGW should not permanently release capacity without call-back rights for winter seasons.
- PGW storage services appear adequate to meet peak requirements.

Tab 13

Docket No. R-14XXX
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: Attached is the Capacity Resource and Asset Management Evaluation Report completed by Summit Energy in January, 2011.

JAN 25, 2011

Capacity Resource and Asset Management

EVALUATION REPORT

SummitEnergy

PGW®

Table of Contents

Executive Summary

After conducting a thorough review of PGW's existing asset portfolio, historical operations, and future load projections; and based upon the assumptions and market dynamics stated herein, Summit has identified several recommendations for the utility's consideration. All recommendations have been made based upon the fundamental premise that PGW's primary objective is providing reliable and cost-effective natural gas supply to its customer base. Each of the recommendations can be considered independently of the others.

After comparing PGW's capacity to its design forecast, Summit recommends the utility evaluate eliminating or reducing portions of its existing asset base, provided favorable asset management arrangements cannot be attained. A stack ranking methodology of the cost of each asset was utilized to help determine the most appropriate areas of focus. Based upon its volume and high cost, Summit recommends the release of PGW's Equitrans storage. In addition to eliminating the Equitrans storage from the utility's portfolio, Summit also recommends consideration be given to reducing its Dominion storage (in addition to its associated Tetco FTS-7 and FTS-8 contracts). We estimate that with a reduction of 10,000 Dth of demand of the Dominion storage (along with the associated storage capacity and FTS transport contracts) PGW would still be capable of serving design scenarios. Despite the utility's ability to meet design scenarios with the recommended capacity reductions, it is important to note that such reductions will increase the utility's reliance on LNG and reduce capacity release credits to the gas cost rate. Additionally, reduction of the Dominion storage from approximately 4 Bcf to 3 Bcf could result in new contract rates that may diminish some or all of the potential savings.

While Summit recommends consideration of the elimination and reduction of some assets, we also recommend maintaining others due to their associated value. First and foremost, we recommend PGW retain all existing long-haul interstate capacity due to both its cost-effectiveness as well as the utility's lateral delivery requirements. Additionally, as both Tetco and Transco are fully subscribed it is questionable whether such capacity could ever be regained in the future if it were surrendered.

While we also currently recommend the retention of PGW's production area storage, the market should continue to be monitored for changing dynamics that would impact or alter the future value of the storage assets. Despite the protection that is afforded against balancing penalties and supply disruptions in the production area, this type of storage becomes less valuable in a marketplace lacking volatility.

Summit also recommends PGW continue to actively monitor potential new asset opportunities. With the significant changes that are taking place in the natural gas complex and particularly in the Northeastern US, it is possible that new supply and/or capacity alternatives could develop that could displace or replace current assets.

When taking into account PGW's assets and historical operations, one additional recommendation is to evaluate the feasibility of creating a more dynamic management of the utility's underutilized long-haul capacity. While the utility currently manages an active capacity release program, it is possible that additional benefits could be gained through administering an even more vigorous program. More participation in weekly long-haul capacity releases could yield incremental returns over and above what has historically been received. Based on current market conditions and the complexities involved, Summit would recommend PGW manage any enhanced release program at this time versus relying on a third party.

The market dynamics in the Northeast have vastly changed in the past several years and are still rapidly evolving. Therefore, Summit recommends a short-term approach to any further contractual asset retention. It is also Summit's belief that PGW would be well served to internally re-evaluate its asset portfolio on a regular basis (annual to every two years) to ensure it can take better advantage of any future market developments.

In conclusion, Summit advocates that PGW utilize the enclosed report to consider these recommendations and take action accordingly.

Introduction and Scope

The following report outlines independent analysis conducted by Summit Energy Services, Inc. (Summit) regarding the natural gas capacity resources of Philadelphia Gas Works (PGW). This assessment was constructed based upon a thorough investigation of the utility's existing gas capacity asset portfolio, the utility's servicing obligations, and a detailed review of existing and projected market fundamentals. The study consisted of the following:

- Review and analysis of PGW current gas supply infrastructure assets (pipeline capacity, storage, and LNG)
- Assessment of range of appropriate levels of capacity resources
- Investigation of alternative supply and/or capacity options
- Examination of value of utilizing third party asset management
- Review of asset management payment structures

Background

PGW initially engaged Summit through a competitive request for proposal to perform a thorough evaluation of both PGW's capacity portfolio holdings and its commodity purchasing strategies. PGW program evaluations have been periodically performed by independent parties in the past, the most recent being a study issued by a third party in 2006. Such studies must be re-evaluated at discrete time intervals to consider changes not only in the load characteristics of PGW itself, but also to evaluate changes that occur in both the commodity and capacity markets.

Summit Approach

Upon engagement, Summit reviewed historical testimony of PGW personnel outlining the utility's operational practices as well as the aforementioned study from 2006. In addition, Summit reviewed testimony from prior Gas Cost Rate (GCR) proceedings.

PGW has historically maintained the perspective that keeping the existing infrastructure portfolio intact best enables the utility to provide safe, adequate, and reliable service to its customers. Although there were recommendations which advocated the future consideration of shedding the most marginal economic assets in the portfolio, the previous study largely supported the utility's viewpoint. A contrary opinion from a GCR proceeding participant, however, called for more definitive action, stating that PGW had a large amount of excess capacity that needed to be relinquished, and that its current portfolio holdings were causing the GCR to be inflated.

As Summit prepared to re-evaluate the PGW portfolio and provide its own assessment, the utility collected and disseminated updated information to Summit including the following:

- Most current information concerning historical design day, design year, and actual delivery send out data
- Utility-controlled Liquefied Natural Gas (LNG) liquefaction and vaporization capacities, boil-off histories, and historical monthly inventories
- Capacity release and off-system sales histories, including both long-term and short-term transactions
- Third party supplier agreements designating volumes, price structures, optionality, delivery points, etc.
- Commodity purchasing program details, including historical purchase information

The provided data was supplemented with questions set forth by Summit as additional information was required, as well as with detailed interviews of PGW strategic and tactical personnel. These discussions provided opportunities to learn about operational constraints and details that were not set forth in the provided documentation. This was particularly necessary with the LNG asset evaluation, as this was not jurisdictional at the interstate level and lacked the visibility of FERC-mandated tariffs for long-haul and storage capacity.

Summit next engaged in its own analysis independent of PGW. This consisted of first establishing a set of assigned costs for each capacity asset in the PGW portfolio. This included a standard set of assumptions involving the commodity cost, heating values, utilization of current interstate pipeline tariffs, and other factors to make sure assets were evaluated using equivalent measures.

Summit included all relevant costs for each asset to assign an "as delivered" cost. This included demand charges, commodity charges, fuel, as well as any carrying costs for assets such as storage and LNG. Storage assets also included transportation for both injection and withdrawal capacity to deliver to the PGW city gate. Additional considerations such as storage cycling requirements and load factor assumptions were also integrated. After each asset was assigned a cost, Summit then stack ranked the assets to ascertain relative costs.

Once such analysis was complete, Summit prepared both a "snapshot analysis" of how PGW is currently managed, as well as a set of recommendations to best position PGW in the future in light of market shifts. These findings and recommendations are incorporated herein.

PGW Historical Operations

Reviewing the historical performance of PGW operations, Summit concludes that PGW has succeeded in its core mission of ensuring that all system delivery requirements are fulfilled. PGW has not had to curtail firm service customers and has been able to satisfy all design day and design winter delivery scenarios. Thus, it is evident that the current asset portfolio is adequate to meet needs now and into the anticipated future. This does not answer the question, however, of whether PGW carries excess capacity in its portfolio. This issue is discussed in the recommendation section of this report.

Long-haul Transportation Capacity

Due to the nature of peaking assets not being required at all times, utilities are naturally over-subscribed (or "long") on their capacity during most periods. While it would be optimal to have "load following" capacity, it is not feasible for pipelines to provide this service. Thus, most interstate pipeline long-haul firm transportation and storage are based upon demand charges for the largest amount of capacity the purchaser requires on a given day. This requires a careful balancing of one's needs.

Generally, PGW has performed well balancing such needs. Interstate long-haul capacity is first scheduled to serve "as needed" daily demand, with any unutilized capacity next being scheduled to deliver gas into either interstate storage or PGW-owned LNG liquefaction facilities. Any excess capacity beyond such needs is released into a relatively liquid secondary capacity market using an internal bidding system supplemented by the applicable interstate pipeline electronic bulletin board (EBB) system. This allows other entities to bid on such capacity, though PGW permits the originally selected bidder to retain a right of first refusal to match the right of the highest bid.

PGW's participation in the secondary capacity markets allows them to effectively recoup or "monetize" assets on otherwise sunk costs. The values of these assets can fluctuate over time, and are typically less valuable in times of lower demand.

Storage Capacity

Storage is critical towards achieving the goal of delivering peak day needs, as interstate capacity alone is insufficient for this task. Interstate storage is another asset that PGW extensively utilizes, and is largely divided into production area storage (Gulf region) and market area storage (Pennsylvania market area). These classifications are important due to their very different strategic characteristics.

Production area storage tends to have large amounts of capacity associated per storage field (many are abandoned gas reservoirs), and usually does not have equivalent long-haul transportation contracts associated directly with it, although there are usually receipt point rights that match the storage field.

Production storage has three primary functions. First, it can be used when there are temporary issues with obtaining gas from the furthest points in the Gulf due to hurricanes or well freeze-offs in the winter season. Owners of such storage can make withdrawals until the supply disruption ends.

Second, variations between actual usage and nominations can be managed with storage assets to avoid daily balancing penalties. Additionally, the potential for large penalties (upward of $50/Dth) to be incurred during Operational Flow Order (OFO) periods would be less likely to materialize, as needed gas can be drawn from storage or unnecessary gas can be injected. This is valuable during crisis times when it is difficult to purchase or sell incremental gas.

Finally, the use of storage in "contango" markets (those where future pricing is significantly higher than current month pricing) make it less expensive to purchase gas in current months, carry volumes in storage, and then withdraw it during higher priced periods. As long as the future month price premium exceeds the cost of the storage assets, storage is a tool for price risk management, in addition to its physical reliability.

Market area storage shares many of the same characteristics as production area storage, but there are some key differentiators. As many of the storage fields have physically less capacity, PGW is required to contract for multiple storage services, each of which has differing pricing and deliverability structures. This does have an ancillary benefit, however, since it effectively diversifies their portfolio across multiple locations, and allows for receipt of gas at additional delivery points in the event of force majeure.

Market area storage is designed to provide security of supply in the event long line purchases are lost, to meet peak day demand and design year requirements, and to provide swing and balancing service. In addition, it provides a physical price hedge for a portion of the portfolio. PGW manages these fields to be regularly "cycled" according to minimum pipeline requirements.

PGW-Owned LNG Infrastructure

PGW has substantial LNG assets that are owned and maintained internally, including storage facilities at Richmond (4,045,800 Mcf capacity) and Passyunk (253,000 Mcf capacity). These assets are critical to the utility's ability to meet design day capacity needs due to their large vaporization and send out capabilities (411,000 Mcf/day and 47,000 Mcf/day, respectively). As is typical with LNG storage managed by utilities, PGW holds LNG in order to meet high deliverability needs on a short-term basis, often in the form of "needle-peak" demand spikes in the winter season.

LNG has several drawbacks when compared to more traditional natural gas deliveries. First, liquefaction occurs at much slower rates than the vaporization itself, so replenishing exhausted supplies requires considerably more time. While a market exists for delivered LNG, the associated costs are uneconomical. Second, PGW's current liquefaction system achieves maximum efficiency only during select parts of the year (late winter and autumn), so it is a rigid schedule.

While there are limitations, the LNG capacity PGW owns has some unique benefits. First, the capacity itself is substantial (approximately 4.3 Bcf). Although it would only satisfy 10 days of deliverability at full utilization, the LNG provides insurance against a catastrophic upstream event. Second, it serves as an economic arbitrage tool in the event of a price spike. In such an event, PGW could look to sell incoming pipeline/storage gas to another delivery point for a short period of time, and displace such delivery with LNG. Thus, while illiquid relative to capacity markets, LNG assets could actually result in higher monetization in selected instances. Lastly, as they are self-owned, these LNG assets are not subject to the same rules governing interstate storage, including cycling requirements, variable tariff pricing over time, etc.

Capacity Monetization

PGW employs a variety of strategies to balance its own load requirements and effectively mitigate demand charges. They have increasingly become an active participant in the capacity release market and generally have had little difficulty finding a third party to whom it could release its excess pipeline demand. PGW releases capacity as available on either a monthly or semi-monthly basis dependent upon how actual load is performing relative to plan. They have been successful at obtaining values for some longer term and winter releases near, at, or above maximum tariff rates. This practice helps to offset nearly all demand charges associated with those volumes that are released. Conversely, shorter term releases made during the summer season have often yielded values that are well below actual demand cost, which in turn fail to recover the total cost of the released volumes. Over recent years, PGW's expanded capacity release activities have yielded an average release benefit increase of over 600% when comparing the early 2000's to the years leading up to 2010.

In addition to the capacity release strategy, PGW historically has looked at off-system sales (i.e., bundling capacity availability with natural gas itself and selling to third parties at delivery points other than PGW). This option has several limitations per PGW's current resource mix. The off-system sales market is much more short-term in nature (often for a few days at most) and for maximum benefits requires marketing of the supply. Additionally, unlike capacity release, which utilizes the pipeline EBB to monitor and credit back demand dollars, PGW has to devote resources to nominate gas and bill the buyer accordingly. This method of cost recovery works best when pricing substantially rises due to system constraints or extreme weather conditions. In select years past, this was strictly done during instances where PGW was solicited by a third party. Such activities yielded financial benefit for the utility and were based upon existing market conditions.

PGW has also recently employed a one year asset management agreement for a portion of its storage capacity. This type of release has the potential to recover all or more than the value of the actual demand charges. A third party will often pay a premium for such assets (as often pipeline storage can be oversubscribed) to more effectively arbitrage trading positions.

PGW has utilized this strategy successfully for their Transco WSS production storage, releasing approximately half of their storage position to a third party at a rate that exceeded the utility's actual tariff costs. Under this Asset Management Agreement (AMA), PGW releases 1.5 Bcf of Transco WSS storage capacity in return for $1.1 million via monthly payment installments. The third party arrangement, which is currently the only instance of PGW utilizing the services of an outsourced asset manager, has been a lucrative agreement for the utility based on the market value of the storage capacity. That said, it should be noted such values of storage will fluctuate with the market and the value that can be derived will vary.

Assumptions

Summit approached its analysis with a core set of assumptions. Some of these are more numerical in nature to better evaluate the assets in the portfolio on an "apples to apples" basis. Others more specifically focus around organizational goals.

Reliability

Summit operated under the fundamental premise that PGW has a mandated public service duty to ensure that its service delivery requirements must always be met. This is a different operational mindset than what is held by many non-utility entities. For instance, a for-profit industrial might elect to shut down production and sell off any gas if premium prices existed in the marketplace. Other companies, such as trading entities, might incorporate a greater element of risk into their decision-making by reducing capacity commitments and relying on supply availability at the time it is required.

Summit also focused on unique attributes of the PGW system, especially its reliance on interstate pipeline laterals and its limited LNG liquefaction capabilities. Although PGW is served by the interstate pipeline system, PGW is actually fed by laterals off of the main pipeline system which constrains deliveries during winter peak demand times when the laterals are delivering full requirements. In addition, Summit examined the relative subscription rates of capacity and storage on the interstate systems to determine the availability to replace any asset removed from the capacity portfolio. Based on such analysis, one core assumption is that there currently tends to be a limited ability to replace service with alternative firm asset commitments. Last, Summit assumed that a financial commitment (i.e., a delivered contract with liquidated damages) was inferior to a physical asset, due to downstream damage that could be created in the event the supplier was unable to fulfill delivery requirements during a peak day.

Economics

Summit prepared its analysis with a standard set of economic assumptions to ensure uniformity as it evaluated each capacity asset in the PGW portfolio. While such assumptions would change over the contract life of the respective assets and under varying commodity pricing thresholds, the relative values of each asset generally remain consistent.

Forward pricing of natural gas changes daily, so to incorporate consistency in our analysis, our first assumption was a base case NYMEX estimate of $5.00/Dth. Additionally, analysis was run using NYMEX estimates ranging from $3.50/Dth to $7.00/Dth in various scenarios.

Summit also used currently effective tariffs to project demand and commodity charges, fuel ratios and storage ratchet requirements. Such numbers are subject to future rate case adjustments, but generally have more stability than the natural gas commodity itself. While different pipeline filings could affect the value of one capacity asset versus another, such changes occur infrequently and can be evaluated periodically to ensure where they each rank from a cost standpoint. PGW has swing contracts within their supply portfolio that carry an additional pipeline demand component, as these are no-notice contracts. The models do not take these additional demand charges into account, as the impact of these charges on the stack ranking would be negligible.

Operations

Where necessary, Summit assumed a Btu conversion of 1.03 to convert Mcf measurements to Dth. This is also the value used by PGW in many of their conversions, and typically, there is low variation in Btu factors across interstate pipelines.

Historical data indicates consistent year-over-year load declines independent of weather factors, which has been confirmed by PGW's own analysis. While this decline is generally modest (approximately half a percent per year), this reinforces the need to perform an internal review of its assets based on current and future needs. For our analysis, Summit used the 2010/2011 Design Day/Year model (shown on next page). Summit did not model asset needs based on a normal load forecast as this was considered imprudent given PGW's core mission of customer reliability.

Second, Summit assumed historical storage injection and withdrawal patterns, including fulfilling cycling requirements as governed by tariffs. This includes injecting gas on a daily and seasonal basis, which limits maximizing more aggressive "fill" strategies that would be based solely on price. Similarly, withdrawal from each individual storage field creates both a floor and a cap on deliverability. Summit assumed compliance with applicable pipeline tariffs as well as a fairly consistent cycling pattern based upon historical data.

2010-11 Design Forecast* (MDth)

	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11
1	42.0	42.5	62.3	115.3	678.7	645.5	475.2	282.3	189.3	42.6	42.6	42.3
2	42.0	42.5	89.7	174.6	628.6	585.8	447.3	264.7	155.0	42.6	42.6	42.3
3	42.0	42.5	108.0	204.3	598.6	555.9	419.4	238.4	129.3	42.6	42.6	42.3
4	42.0	42.5	126.2	224.1	588.6	516.1	400.7	229.6	120.7	42.6	42.6	42.3
5	42.0	42.5	135.3	243.8	558.5	506.2	391.4	220.8	112.2	42.6	42.6	42.3
6	42.0	42.5	144.5	273.5	538.5	486.3	382.1	212.0	103.6	42.6	42.6	42.3
7	42.0	42.5	153.6	283.4	518.5	466.4	372.8	203.2	95.0	42.6	42.6	42.3
8	42.0	57.7	162.7	293.3	498.4	456.4	363.5	194.4	95.0	42.6	42.6	42.3
9	42.0	57.7	171.9	303.2	488.4	446.4	354.2	185.6	86.5	42.6	42.6	42.3
10	42.0	65.4	181.0	313.1	478.4	436.5	344.9	176.8	86.5	42.6	42.6	42.3
11	42.0	73.0	190.1	322.9	468.4	426.5	335.6	176.8	77.9	42.6	42.6	42.3
12	42.0	80.6	199.2	332.8	458.4	416.6	326.3	168.0	69.3	42.6	42.6	42.3
13	42.0	80.6	208.4	342.7	448.4	406.6	317.0	159.2	69.3	42.6	42.6	42.3
14	42.0	88.2	217.5	352.6	438.3	396.7	307.7	150.4	60.8	42.6	42.6	42.3
15	42.0	95.9	226.6	362.5	428.3	386.7	298.4	141.6	60.8	42.6	42.6	42.3
16	42.0	103.5	235.7	372.4	418.3	376.8	289.1	132.8	43.6	42.6	42.6	42.3
17	42.0	103.5	244.9	382.3	418.3	366.8	279.8	124.1	43.6	42.6	42.6	42.3
18	42.0	111.1	254.0	392.2	408.3	356.9	270.5	115.3	43.6	42.6	42.6	42.3
19	42.0	111.1	263.1	402.0	398.3	346.9	261.1	106.5	43.6	42.6	42.6	42.3
20	42.0	118.8	272.2	411.9	388.3	337.0	251.8	97.7	43.6	42.6	42.6	42.3
21	42.0	118.8	281.4	421.8	378.3	327.0	242.5	88.9	43.6	42.6	42.6	42.3
22	42.0	126.4	290.5	431.7	368.2	317.1	233.2	88.9	43.6	42.6	42.6	42.3
23	47.5	126.4	299.6	441.6	358.2	307.1	223.9	71.3	43.6	42.6	42.6	42.3
24	47.5	134.0	308.8	451.5	348.2	297.2	214.6	71.3	43.6	42.6	42.6	42.3
25	53.0	134.0	308.8	471.3	338.2	267.3	205.3	44.9	43.6	42.6	42.6	42.3
26	58.6	141.7	317.9	481.2	328.2	257.4	196.0	44.9	43.6	42.6	42.6	42.3
27	58.6	149.3	327.0	491.0	318.2	247.4	177.4	44.9	43.6	42.6	42.6	42.3
28	69.6	164.6	345.3	510.8	298.1	197.6	168.1	44.9	43.6	42.6	42.6	42.3
29	80.7	172.2	372.6	510.8	288.1		149.5	44.9	43.6	42.6	42.6	42.3
30	97.2	195.1	427.4	530.6	258.1		121.6	44.9	43.6	42.6	42.6	42.3
31		218.0		580.0	188.0		84.3		43.6		42.6	42.3

*Based on the temperature pattern for a design year in the PGW Model. PGW's design day send out at 0° is 681,200 Mcf.

Market Dynamics

An analysis of historical market drivers and pricing trends is often effective for establishing a forecast for future contingencies. This approach, however, loses efficacy if new pricing drivers are introduced such that the supply and demand fundamentals of the market are altered. The following analysis reveals that many pre-2007 market conditions are no longer domestic driving factors today. Further, a new paradigm has evolved in the natural gas complex specifically impacting Northeast gas transportation markets.

US Natural Gas Landscape

In 2006 and 2007, most, if not all, energy markets were indicative of the rapid economic growth experienced both domestically in the US, and abroad. Natural gas consumption continued to witness an upward growth trend into 2007, pushing demand to record levels. Optimism of seemingly unstoppable growth for energy helped push fuel prices to elevated levels and had most market analysts expecting an extended upward trend in prices, which in turn resulted in growing investor interest.

Coming out of 2007, demand evidence was compelling: US natural gas consumption in the first half of 2008 exceeded that of 2007, setting new five-year highs. Demand was not alone in supporting prices during this time. After many years of strong investment in natural gas exploration and production (the gas rig count had been setting new highs for four years running), natural gas production in the US was unable to keep pace with demand. The amount of gas in storage was insufficient at five-year average levels. The result: a steady uptrend in pricing through 2008.

The impact of the "Great Recession" on US natural gas consumption was delayed, but by early 2009, demand had fallen to five-year minimums. Despite this, US natural gas production remained very strong as a result of the favorable investment environment of 2008. In fact, gas production in the US set new highs in 2009. High volumes of natural gas in storage resulted and subsequently persisted throughout 2009. As such, gas prices fell coming out of 2008 and heading into 2009.

In mid 2009, US natural gas consumption began showing signs of recovery and had recovered to near five-year highs by early 2010. US natural gas production also continued to show impressive growth as a result of shale production and storage volumes reached an all-time high in November 2010. Logically, gas prices have remained near the $4-$5 range since March.

As we turn to 2011 and beyond, a few major themes emerge as key drivers for the US natural gas market. Demand hinges on industrial market recovery as well as technological advancements through increased investment in the exploration and production industry. The fundamental outlook going forward is for strong growth in production to persist at rates greater than the expected growth in consumption. As such, Summit anticipates prices to remain relatively flat through 2011 and into 2012. Over the next 5 years, our outlook is for the market to move in a slightly upward direction; however, prices are not expected to reach the highs seen pre-2009.

Regional Transportation Pricing Landscape: Northeast

Basis costs in the Northeast historically have been heavily influenced by the incremental escalation of regional natural gas demand while interstate pipeline capacity infrastructure has remained relatively static. The resulting shortage of pipeline capacity to bring sufficient gas into the region created a floor for regional transportation prices making the Northeast a premium gas market. Other regional market drivers like weather, particularly the severity and duration of winter temperatures and precipitation, LNG capabilities, and Canadian gas imports into the region have also been key pricing drivers.

Much has changed in the Northeast since the 2006 study of PGW's assets was completed. The 2006 study was written in the wake of two major hurricanes in 2005 that introduced extreme national natural gas pricing volatility and took significant Gulf supplies off-system for the winter of 2005-2006. Since 2006, we have not seen similar destructive hurricane activity hit producing regions in the Gulf. Subsequently, the credit crisis of 2008 introduced another macro-environment alteration to the industry. Additionally, the cost of obtaining capital for the whole of the industry increased.

The largest market drivers in the Northeast post-2006 have not been the credit crisis nor hurricane activity. Rather, the Northeast natural gas market has responded to simple supply and demand fundamentals consisting of an increase in production and pipeline infrastructure and a simultaneous dip in consumer demand.

In 2008, Northeast natural gas consumption was approximately 9 Bcf/day. In late 2008, the last leg of the Rockies Express Pipeline brought an additional 1.8 Bcf/day into the region via the TCO pipeline system. This provided a 20% boost to Northeast supplies and brought immediate relief to the historically premium regional pricing complex.

Marcellus Shale gas has also introduced increased supply into the Northeast. This intra-region supply is expected to eventually bring as much as 6 Bcf/day into the Northeast's supply mix. Currently, Marcellus Shale is contributing 0.7 to 1.3 Bcf/day of supply. The long-term impact of this shale find is dependent on the following: further build-out of a pipeline gathering system that will connect Marcellus Shale gas to major interstate pipelines, the domestic price of natural gas (which will impact break-even rates for Marcellus drilling rigs), and environmental legislation regarding the hydraulic fracturing required to pull shale gas from underground formations.

The natural gas pipeline infrastructure in the Northeast has experienced exponential growth since 2009. Fifteen new pipeline extensions are set to be completed in the Northeast region by 2013 that will allow approximately 11 Bcf/day[1] in additional gas throughput. This increase in infrastructure is a dramatic shift from the early to mid 2000's when new pipeline build-outs were far less common. Historically, due to the lack of infrastructure, basis prices were bid up to premium levels as various parties competed for the remaining pipeline volumes that were not consumed by upstream pipeline market

[1] www.ferc.gov/industries/gas/gen-info/horizon-pipe.pdf

participants. The new infrastructure has already provided significant relief to regional basis prices and has allowed the new supply from the Rockies and Marcellus Shale to move with more freedom in the region.

While the EIA has not yet released its calendar-year 2010 natural gas consumption numbers for the Northeast states, we expect demand to have decreased proportionately to the broader macro-economic impact of the United States recession.

The changes to the supply and demand landscape of the Northeast outlined above have caused regional transportation prices and assets to decline in value. Excess intra-region supply threatens to displace a large portion of gas entering the region from the Gulf, Rockies, and Canada. While interstate pipeline capacity assets into the Northeast, particularly from the Gulf, have managed to retain value (likely due to a 'wait-and-see' approach as to whether the new supply paradigm will persist in the Northeast), regional basis prices have retreated significantly since early 2009. The new supplies have all but removed the historical pricing volatility in the region.

Summit Analysis Process

Based upon Summit's historical findings of the PGW program as well as the above mentioned dynamics in the marketplace that have occurred in the last several years, Summit designed its own "cost to deliver" model that effectively stack ranks each contracted capacity asset in the PGW portfolio. While the model is based upon the assumptions stated herein, these have been examined through multiple scenarios, and our analysis indicates relative asset rankings generally remain consistent.

The model integrated financial costs including the natural gas commodity as well as associated tariff charges. Additional costs associated with storage assets, such as transportation costs to deliver withdrawals from storage and applicable carrying costs unique to each storage agreement, were also incorporated.

These assets were stack ranked solely on a cost basis. In the first set of scenarios, cost models assumed no spread between winter and summer prices (i.e., NYMEX values flat throughout year). As seen in the table on the following page, the impact of increases in commodity cost to the relative weighted average costs is marginal. Even if NYMEX values were to return to their historical settlement highs, the stack rankings within each category remain consistent.

		NYMEX: $3.5/Dth Year-Round	NYMEX: $5/Dth Year-Round	NYMEX: $7/Dth Year-Round
Market Area Storage	Equitrans SS3	$7.665	$9.442	$11.811
	Tetco SS1-A*	$6.307	$8.035	$10.339
	Dom GSS Tetco FTS8	$6.062	$7.766	$10.037
	Dom GSS Tetco FTS7	$6.022	$7.726	$9.998
	Tetco SS1-B	$5.743	$7.471	$9.776
	Transco GSS	$5.314	$6.976	$9.192
	Transco S2	$5.290	$6.955	$9.174
	LNG	$4.329	$5.953	$8.119
Production Area Storage	Transco ESS1	$5.447	$7.036	$9.155
	Transco ESS2	$5.447	$7.036	$9.155
	WSS Transco FT*	$4.594	$6.200	$8.341
Long-Haul Transport	Tetco CDS	$4.504	$6.145	$8.333
	Tetco FT-1	$4.490	$6.130	$8.318
	Transco FT	$4.237	$5.827	$7.947

*Tetco SS1-A and WSS Transco FT are primary tools employed by PGW to avoid interstate pipeline balancing penalties on differentials between actual consumed and delivered volumes.

Next, cost models assumed $5.00 NYMEX in summer months, with summer-to-winter spreads of $.50, $1.00, and $2.00. Since most gas is consumed in the winter months, the model assumed storage gas was bought in the summer and used in the winter, while long-haul was based on winter pricing. As seen in the table below, growth in summer-to-winter spreads increases the value of all storage assets, and the lowest cost storage options begin to provide a lower weighted average cost of gas than long-haul; however, the increased value does not outweigh the costs for Equitrans in any of the sample scenarios. In addition, such large summer-to-winter commodity spreads are not expected to materialize in the foreseeable future, as spreads have eroded in recent years due to gas-fired power generation and high storage levels.

		NYMEX: $5/Dth Summer, $5.5/Dth Winter	NYMEX: $5/Dth Summer, $6/Dth Winter	NYMEX: $5/Dth Summer, $7/Dth Winter
Market Area Storage	Equitrans SS3	$9.442	$9.442	$9.442
	Tetco SS1-A	$8.035	$8.035	$8.035
	Dom GSS Tetco FTS8	$7.766	$7.766	$7.766
	Dom GSS Tetco FTS7	$7.726	$7.726	$7.726
	Tetco SS1-B	$7.471	$7.471	$7.471
	Transco GSS	$6.976	$6.976	$6.976
	Transco S2	$6.955	$6.955	$6.955
	LNG	$5.953	$5.953	$5.953
Production Area Storage	Transco ESS1	$7.036	$7.036	$7.036
	Transco ESS2	$7.036	$7.036	$7.036
	WSS Transco FT	$6.200	$6.200	$6.200
Long-Haul Transport	Tetco CDS	$6.692	$7.239	$8.333
	Tetco FT-1	$6.677	$7.224	$8.318
	Transco FT	$6.357	$6.887	$7.947

Based on the scenarios examined on the previous page, changes in the absolute cost of gas do not have a significant impact on the relative cost of delivery options. Additionally, large summer-to-winter commodity spreads are not expected, and modest spreads do not result in changes to the assessment of the highest cost assets. Thus, recommendations for optimization are based on the $5.00 year-round NYMEX scenario.

Asset Stack Ranking

Market Area Storage	Max Storage Quantity (Dth)	Storage Demand (Dth)	Estimated WACOG ($/Dth)
Equitrans SS3	522,500	4,998	$9.442
Tetco SS1-A	2,647,080	44,118	$8.035
Dom GSS Tetco FTS8	3,007,810	22,495	$7.766
Dom GSS Tetco FTS7	911,161	6,815	$7.726
Tetco SS1-B	2,462,120	20,847	$7.471
Transco GSS	4,123,733	53,871	$6.976
Transco S2	466,554	5,191	$6.955
LNG	4,428,073	469,680	$5.953

Production Area Storage	Max Storage Quantity (Dth)	Storage Demand (Dth)	Estimated WACOG ($/Dth)
Transco ESS1	482,792	47,986	$7.036
Transco ESS2	656,013	65,201	$7.036
WSS Transco FT	3,335,909	39,246	$6.200

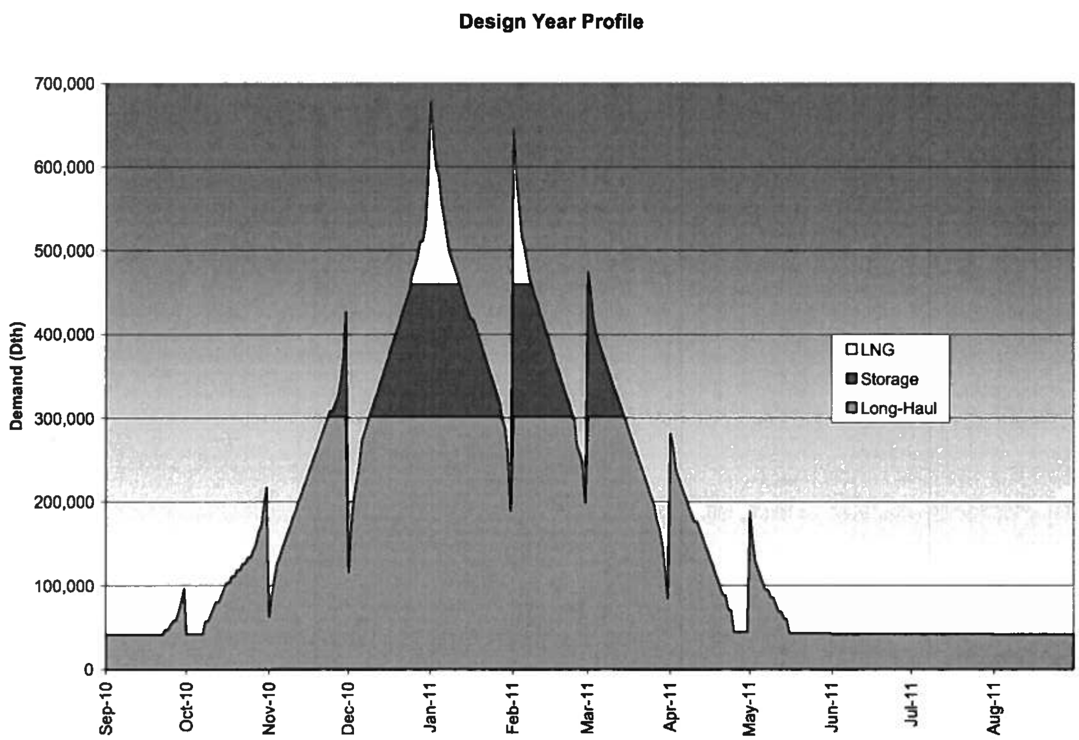
Long-Haul Transport	Capacity (Dth)	Estimated WACOG ($/Dth)
Tetco CDS	75,000	$6.145
Tetco FT-1	59,822	$6.130
Transco FT	167,179	$5.827

Based upon our initial analysis of storage assets (table above), Equitrans storage was the highest cost delivered asset to serve PGW. Tetco SS1-A was the next highest cost asset due to its relatively high reservation of demand, though this asset plays a significant part in meeting PGW's balancing needs on the Tetco pipeline. Long-haul transportation across Tetco or Transco is intuitively the cheapest option, as it is taken directly from the production area, assessed fuel and transportation costs, and then delivered directly to the market. Storage requires additional costs (demand, storage capacity, fuel, and associated transportation), which raise the total cost of delivery.

After the initial stage of cost-based stack ranking, Summit next created a delivery prioritization model that incorporated relative receipt and delivery constraints of each asset. Thus, long-haul and short-haul interstate capacity is inherently limited by the maximum daily quantity (MDQ) of each transport agreement. Similarly, some storage agreements not only have limits on their injections, withdrawals, and total capacity, but also on seasonal requirements such as ensuring certain percentages of gas in storage are actually withdrawn. Finally, PGW-owned LNG not only has capacity restrictions, but also operational constraints on its liquefaction. These constraints are more physical than contractual.

Summit then incorporated the 2010-2011 peak design consumption model and evaluated alternative scenarios when considering the appropriate ways to guarantee deliveries are met. This included ensuring that maximum deliveries were made via already contracted assets delivering at variable costs, thus avoiding additional incremental purchases. Also, LNG reserves were always maintained to ensure adequate deliverability from vaporization would exist for any necessary peak day/year.

Given PGW's limited capability to aggressively refill its LNG capacity, Summit not only evaluated the needs of a single design year, but also that of two consecutive design years. The results illustrate that as the highest cost storage capacity is eliminated, PGW quickly approaches a scenario where it might not be able to meet its operational requirements.



LNG Usage – Design Year Scenarios

Non-LNG Assets	Non-LNG Capacity (1)	LNG Inventory Needed for Design Winter (1,2)	LNG Inventory Needed for Consecutive Design Winters (1,3)
All current assets	460,336	2,237,800	2,965,601
Current asset mix less 5,000 Dth of demand	455,336	2,371,900	3,233,801
Current asset mix less 7,500 Dth of demand	452,836	2,441,900	3,373,801
Current asset mix less 10,000 Dth of demand	450,336	2,513,053	3,516,106
Current asset mix less 12,500 Dth of demand	447,836	2,586,075	3,662,151
Current asset mix less 15,000 Dth of demand	445,336	2,664,129	3,818,257

(1) Volumes in Dth.
(2) Volume represents the design demand in excess of non-LNG capacity, inclusive of boil-off volumes for withdrawal season.
(3) Volume represents the minimum amount of LNG necessary at the beginning of withdrawal season in year 1 to meet two consecutive design winters; this assumes 2,000,000 Dth of liquefaction in a calendar year.

Summit's modeling revealed that any combination of assets that satisfy consecutive design year requirements would always result in some unutilized capacity in any reasonable asset mix. Given that PGW will necessarily be "long" in most circumstances, Summit then proceeded to evaluate which assets could either be directly monetized (capacity release) or indirectly monetized (asset management relationships, off-system sales).

Outsourced Asset Management

PGW requested that Summit advise the Company regarding possible AMAs, including a review of the best practices regarding the payment structure of such arrangements. An asset management program provides for the utility to turn over the management of all or some of its assets to a third party. Under this arrangement, the asset manager commits to satisfy the utility's delivery obligations in return for having the ability to use the asset or assets however the manager decides when such deliveries are not required. The release of one's entire asset portfolio is a popular strategy for smaller municipalities (~5 Bcf or less of annual firm requirements) who will bundle and assign their assets while simultaneously fulfilling their delivery requirements. It enables the utility to reap a larger recovery of dollars than they would have by self-managing their portfolio.

With the exception of the aforementioned AMA for a portion of PGW's storage, PGW does not currently employ this type of asset management strategy and generally retains institutional self-control of its asset base with the exception of capacity release programs. There are numerous asset managers in the marketplace with the primary objectives of providing reliable gas supply to the utility city gate, managing the utility's existing asset base, and optimizing the value of such contracts. Additionally, there are numerous natural gas distributors who utilize the services of a third party asset manager. Despite this utilization, however, the strategy is not necessarily the most appropriate approach for all gas distributors, nor does it appear to be a rapidly increasing practice. Instead, many utilities regularly perform internal review of their capacity needs.

For a utility, releasing control and management of one's assets to a third party can, at times, pose significant risks and complexities that may offset the benefits achieved by the program. The primary benefit that can be achieved under a third party asset management agreement is the optimization of those assets, some of whose benefits may otherwise be unrealized. Outsourced firms may be better positioned to deliver optimization value because of the following:

- Inherently possess larger scale and flexibility
- More substantial and broader market presence/expertise
- Greater resource availability
- Core operational function

Additionally, there may be value derived from an outsourced AMA as it may enable the utility to focus more intently on customer service and its distribution operations.

While there can be benefits from AMAs, there are also numerous risks to consider. Some of the risks that may exist for a gas distributor evaluating such an arrangement consist of the following:

- Diminished control over a primary business function
- Loss of expertise in a key operational arena
- Exposure to counterparty risk
- Program profitability limitations
- Performance/auditing validation

If PGW considers the possible utilization of an outsourced asset management firm, the utility should carefully weigh the pertinent risks and benefits to ensure the goals of the program align with their overall business objectives. PGW should also consider any internal operational benefits or constraints that may enhance or deter the introduction of such a third party firm. In addition, it is prudent to be cognizant of futures pricing and market dynamics in order to assess the potential viability and profitability of entering an AMA.

Current market levels reflect a summer-to-winter spread differential of approximately \$0.55/Dth, therefore demonstrating a relatively low level of potential profit should any holder look to arbitrage a storage asset. This can be contrasted with market levels from December 2009 (one year ago) when a summer-to-winter spread differential of approximately \$1.00/Dth existed in the market. In this example, the asset's potential value was nearly cut in half over just a 12-month span. A more distant market snapshot from the 2006 – 2007 timeframe would reflect a \$3.00/Dth differential. This second example renders a \$2.45/Dth decrease in value when compared to current market. These various points in time demonstrate how storage profitability can rapidly erode in an ever-changing marketplace.

Due to Summit's market outlook, we do not anticipate a significant increase in the summer-to-winter spreads over the short-term, thus reducing the overall value that can be derived from PGW's storage assets. Because of current market conditions and the aforementioned spread analysis, the likelihood of interested parties willing to enter AMAs is reduced as is the compensation that could be realized.

However, due to the nature of the evolving natural gas market, individual PGW assets may present an AMA opportunity (as opposed to a third party assuming the entire utility portfolio). This is due to the fact that many niche counterparties might ascribe a higher value to a specific asset than another based upon their own unique requirements. As an example, a growing producer with Marcellus Shale production in Pennsylvania might highly value storage and short-haul capacity, but have little interest in long-haul capacity from the Gulf coast. Thus, an exploration of the options surrounding each independent asset could yield greater value than the entire portfolio as well as increase the number of interested parties.

Should market fundamentals support entering into an AMA, there are various forms of compensation that can be structured with the asset manager. The most prevalent payment constructs consist of 1) outright fixed payment over the term of the agreement and 2) shared-benefit payments based on a percentage split of the gains from the optimization. An asset with a greater value will typically render increased flexibility in terms of negotiating compensation structures as well as potentially other contractual criteria. Ultimately, each party's projected valuations of the asset(s), risk appetite, and regulatory constraints can shape the compensation structure of the agreement.

Due to the nature of PGW's core objectives of providing reliable and cost-effective gas supply to its customer base, Summit would consider a set monthly payment schedule as a best practice, provided such payment represents a value PGW deems as fair and appropriate for such asset(s) in the marketplace. This type of structure would produce guaranteed payments that would benefit ratepayers. By securing a set value for the asset upon entering the AMA, market risk can be eliminated and therefore a known compensation threshold would be established. Furthermore, a fixed price agreement avoids the speculative nature associated with a shared-benefit arrangement that is reliant upon future market outcomes to determine its revenue.

Summit Recommendations

Based upon our analysis of current PGW operating parameters, existing and continuing market trends, and an integrated analysis, Summit makes the following recommendations.

1. **Evaluate elimination or reduction of portion of current asset base after assessing asset management opportunities, and leverage PGW-owned LNG assets.**

    - Eventual release of Equitrans storage as it is the highest unit cost asset in the PGW portfolio; the net cost of this asset per year is approximately $541,000 (after adjustments for net capacity release credits). However, due to contractual notification of abandonment provisions and the unique geographical position of this asset within the Marcellus Shale supply basin, it would be prudent to first perform an RFP to determine if opportunity exists for a third party AMA that would guarantee value above PGW's cost.
    - While Tetco SS1-A is the next highest cost delivery option in the stack ranking, it provides PGW with flexibility in balancing load. For every 1 degree of variance between actual and expected temperatures, PGW experiences a change in demand of approximately 10,000 Dth. Since PGW is able to retroactively balance their load through their SS1 assets, PGW's exposure to balancing penalties is reduced. Hence, Tetco SS1 assets should be retained.
    - The next highest cost asset is Dominion storage, along with its Tetco FTS-7 and FTS-8 contracts. Reduction of 10,000 Dth of demand at contract renewal (along with associated storage capacity and FTS transport contracts) would not impede PGW's ability to serve customers in design scenarios. The net cost of this asset per year is approximately $670,000 (after adjustments for net capacity release credits). It is important to note that there is potential that FTS-7 and FTS-8 contracts could eventually bring Marcellus Shale gas into PGW, thereby changing their functionality and subsequent value. Since the Dominion agreement is specially negotiated, any subsequent renewal needs to factor in both the risk and opportunities of both new pricing and delivery terms changing; reduction of the Dominion storage from approximately 4 Bcf to 3 Bcf could result in new contract rates that may diminish some or all of the potential savings.
    - PGW should maintain their LNG inventory consistent with the appropriate level of risk, understanding that their liquefaction capabilities are limited, in order to serve consecutive design winters. Any elimination and/or reduction of designated assets would necessarily entail a greater reliance upon PGW's own LNG assets.
    - Many natural gas utilities in PA and surrounding areas do not have utility-owned LNG facilities. For those that do, LNG usage on a peak design day comprises of approximately 27% of the total portfolio; however, when propane is incorporated with LNG into peak day usage for these same utilities, the proportion increases to 32%. Currently, PGW's LNG comprises 32% of their peak design day portfolio. Reducing portions of their non-LNG capacity as referenced in this report would increase this amount to 34%.

2. **Production area storage still worthwhile assets; however internal evaluation should be an on-going process**

   - It serves as protection against supply area production "shocks" and interstate pipeline balancing penalties.
   - It is valued as a hedging tool on inter-seasonal basis becoming less valuable as market volatility has flattened.
   - Monetization opportunities exist with asset managers, but value may decrease with lessened volatility.
   - Internal evaluation of WSS and Eminence storage value should occur regularly.

3. **Maintain current long-haul interstate capacity allocations**

   - Pipeline lateral delivery requirements necessitate preservation of delivery rights.
   - It is the least expensive delivery option.
   - Transco and Tetco capacity to market area is currently fully subscribed and could potentially be lost if surrendered.
   - Long-haul assets are easiest to monetize when not required due to liquid secondary release market.

4. **Evaluate more dynamic/active resource management (internal or external) for underutilized assets**

   - Traditional asset management (entire portfolio turnover to third party with payment/shared savings structure) is likely unworkable due to complexity and declining liquidity of capable providers.
   - Certain individual assets, particularly those where long-term elimination or reduction is contemplated, should be bid out for potential AMAs to validate the market value of such assets against PGW's costs.
   - More aggressive tactics such as weekly long-haul capacity releases marketed to others should be considered even if potentially requiring additional resources.

5. **Monitor supply/capacity market for more economical infrastructure**

   - Marcellus Shale/transport projects should be entertained to determine if they can displace Transco/Tetco storage and/or portion of LNG-filled capacity.
   - Opportunities to increase long-haul capacity at expense of short-haul capacity/storage also should be considered.
   - Both history and anticipated infrastructure projects strongly suggest that market pricing will be fluid and volatile for the foreseeable future. This makes forecasting the optimal asset mix impossible for any substantial length of time. Thus, PGW is best positioned to continuously evaluate its assets by not committing to long-term contracts, thus maintaining flexibility to shift its portfolio between short-haul and long-haul pipeline capacity and its own LNG capacity.

Adoption of Recommendations and Path Forward

Summit advocates that PGW utilize this report and consider these recommendations, while also establishing processes to more fully monetize its existing capacity assets. In addition, the market dynamics in the Northeast have vastly changed over the past several years and appear to be still evolving rapidly. Thus, Summit recommends a short-term approach to any further contractual asset retention and PGW would be well served to internally re-evaluate its asset portfolio on a regular (annual to every two years) basis to ensure it can take better advantage of any future market developments.

Tab 14

Docket No. R-14XXX

Item 53.64(i)(1)

Philadelphia Gas Works
Pennsylvania Public Utility Commission
52 PA Code 53.61, et seg.

Item 53.64(i) Utilities shall comply with the following:

(1) Thirty days prior to the filing of a tariff reflecting increases or decreases in purchased gas expenses, gas utilities under 66 Pa.C.S. § 1307 (f) recovering expenses under that section shall file a statement for the 12-month period ending 2 months prior to the filing date under 66 Pa.C.S.§ 1307(f) as published in accordance with subsection (b) which shall specify:

(i) The total revenues received under 66 Pa.C.S. § 1307(a), (b) or (f), including fuel revenues received, whether shown on the bill as 66 Pa.C.S.§ 1307(f) as published in accordance with subsection (b) which shall specify:

(ii) The total gas expenses incurred.

(iii) The difference between the amounts in sub paragraphs (I) and (ii).

(iv) Evidence explaining how actual costs incurred differ from the costs allowed under subparagraph (ii).

(v) How these costs are consistent with a least cost fuel procurement policy, as required by 66 Pa.C.S. § 1318 (relating to determination of just and reasonable natural gas rates).

Response: Please see attached schedule. Additionally, please refer to Item 53.64(c)(6) for a detailed discussion regarding the company's least cost fuel procurement policy.

CALENDAR YEAR 2013
PHILADELPHIA GAS WORKS
C-FACTOR RECONCILIATION

MONTH		NET COST OF FUEL 1 ($)	TOTAL GCR REVENUE BILLED 2 ($)	C FACTOR % of GCR 3	C FACTOR REVENUE BILLED 4 = (2 * 3) ($)	LOAD BALANCING REVENUE 5 ($)	LNG SALES GCR BILLED REVENUE 6 ($)	TOTAL C FACTOR REVENUE BILLED 7 = (4 + 5 + 6) ($)	NATURAL GAS REFUNDS 8 ($)	OVER/ (UNDER) RECOVERY 9 = (7 + 8 - 1) ($)
JANUARY	2013	41,124,132	43,400,372	99.6%	43,221,692	89,367	0	43,311,059	0	2,186,927
FEBRUARY		35,260,230	47,360,251	99.6%	47,165,267	90,760	0	47,256,027	0	11,995,797
MARCH		33,485,716	42,383,521	98.1%	41,581,367	93,455	0	41,674,822	0	8,189,106
APRIL		16,953,858	30,030,863	96.8%	29,064,108	60,054	0	29,124,162	0	12,170,304
MAY		12,808,440	13,364,314	96.8%	12,934,090	73,869	4,812	13,012,771	0	204,331
JUNE		9,104,852	8,400,244	96.8%	8,127,825	90,123	26,147	8,244,096	0	(860,756)
JULY		10,061,977	6,051,881	96.7%	5,854,103	90,928	99,263	6,044,293	1,767	(4,015,917)
AUGUST		8,483,293	5,649,100	96.7%	5,464,484	90,897	131,125	5,686,506	60,795	(2,735,992)
SEPTEMBER		9,836,662	6,080,882	99.0%	6,021,220	91,349	120,609	6,233,178	0	(3,603,484)
OCTOBER		15,118,812	6,840,967	101.6%	6,948,891	95,292	100,825	7,145,008	0	(7,973,804)
NOVEMBER		27,283,861	17,006,643	101.6%	17,274,943	93,730	92,138	17,460,811	0	(9,823,050)
DECEMBER		38,336,338	33,832,133	101.6%	34,365,875	99,033	96,182	34,561,090	0	(3,775,248)
Totals		257,858,171	260,401,170		258,023,865	1,058,857	671,101	259,753,823	62,562	1,958,214

STATEMENT OF RECONCILIATION
UNIVERSAL SERVICES & ENERGY CONSERVATION SURCHARGE
CALENDAR YEAR 2013

Month		Applicable Volumes	USC Charge	USC Revenue Billed	USC Expenses	Monthly Over/(Under) Recovery	Cumulative Over/(Under) Recovery
December 2012							($4,305,500)
January 2013	Actual	8,011,065	$ 2.0231	$ 16,207,185	$ 20,806,264	$ (4,599,079)	($8,904,579)
February	Actual	8,733,933	$ 2.0231	$ 17,669,619	$ 21,468,788	$ (3,799,170)	($12,703,748)
March	Actual	7,334,853	$ 2.0735	$ 15,208,817	$ 18,309,930	$ (3,101,113)	($15,804,862)
April	Actual	4,990,006	$ 2.1239	$ 10,598,274	$ 11,471,064	$ (872,790)	($16,677,652)
May	Actual	2,266,270	$ 2.1239	$ 4,813,331	$ 4,086,611	$ 726,721	($15,950,931)
June	Actual	1,468,607	$ 2.0716	$ 3,042,292	$ 146,091	$ 2,896,201	($13,054,730)
July	Actual	1,119,025	$ 2.0192	$ 2,259,535	$ (1,088,883)	$ 3,348,418	($9,706,312)
August	Actual	1,050,483	$ 2.0192	$ 2,121,136	$ (665,482)	$ 2,786,618	($6,919,694)
September	Actual	1,177,368	$ 1.9462	$ 2,291,393	$ (1,707,399)	$ 3,998,792	($2,920,902)
October	Actual	1,435,177	$ 1.8732	$ 2,688,374	$ (369,357)	$ 3,057,730	$136,828
November	Actual	3,421,654	$ 1.8732	$ 6,409,441	$ 5,764,138	$ 645,303	$782,132
December	Actual	6,701,383	$ 1.7880	$ 11,982,073	$ 13,299,609	$ (1,317,536)	($535,405)

USC Expenses	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Total
ELIRP Expense	$ 1,075,076	$ 872,125	$ 647,361	$ 40,240	$ 1,343,847	$ 852,976	$ 777,559	$ 1,491,255	$ 31,547	$ 530,549	$ 763,865	$ 799,164	$ 9,225,565
ELIRP Labor	$ 7,834	$ 7,951	$ 10,454	$ 8,188	$ 10,381	$ 9,339	$ 8,347	$ 34,561	$ 7,337	$ 7,370	$ 19,928	$ 7,314	$ 139,004
CRP Discount	$ 17,968,024	$ 18,835,842	$ 15,997,508	$ 10,110,894	$ 1,794,573	$ (1,520,234)	$ (2,632,669)	$ (2,857,389)	$ (2,491,002)	$ (1,676,044)	$ 3,993,630	$ 11,198,218	$ 68,721,352
CRP Forgiveness	$ 547,865	$ 497,360	$ 587,261	$ 580,488	$ 594,106	$ 593,741	$ 592,891	$ 513,948	$ 583,851	$ 572,257	$ 514,189	$ 462,173	$ 6,640,131
Senior Citizen Discount	$ 1,207,464	$ 1,255,510	$ 1,067,346	$ 731,254	$ 343,703	$ 210,268	$ 164,990	$ 152,143	$ 160,868	$ 196,511	$ 472,526	$ 832,740	$ 6,795,323
Bad Debt Expense Offset*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 20,806,264	$ 21,468,788	$ 18,309,930	$ 11,471,064	$ 4,086,611	$ 146,091	$ (1,088,883)	$ (665,482)	$ (1,707,399)	$ (369,357)	$ 5,764,138	$ 13,299,609	$ 91,521,374
CRP Participation													
Rate Case Participation Rate	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	84,000	
Actual Participation Rate*	75,387	75,671	76,151	76,942	77,321	76,647	75,549	74,349	73,924	72,598	70,464	68,458	
CRP Under(Over) Participation	8,613	8,329	7,849	7,058	6,679	7,353	8,451	9,651	10,076	11,402	13,536	15,542	
Average Shortfall Per CRP Participant													
CRP Discount	$ 17,968,024	$ 18,835,842	$ 15,997,508	$ 10,110,894	$ 1,794,573	$ (1,520,234)	$ (2,632,669)	$ (2,857,389)	$ (2,491,002)	$ (1,676,044)	$ 3,993,630	$ 11,198,218	
Actual Participation Rate	75,387	75,671	76,151	76,942	77,321	76,647	75,549	74,349	73,924	72,598	70,464	68,458	
Average Shorfall per CRP Participar	$ 238	$ 249	$ 210	$ 131	$ 23	$ (20)	$ (35)	$ (38)	$ (34)	$ (23)	$ 57	$ 164	
Shortfall*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Bad Debt Expense Offs 7.1%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

*Bad Debt Expense Offset Applicable When Actual CRP Participation Exceeds 84,000

Tab 15

Docket No. R-14XXX
Item 53.65 (1)

<u>Philadelphia Gas Works</u>

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

Item 53.65 (1)

The costs of the affiliated gas, transportation or storage as compared to the average market price of other gas, transportation or storage and the price of other sources of gas, transportation and storage.

Response:

PGW has no affiliates, see response to 53.64(c)(1) for price of gas, transportation and storage.