Tab 10

Docket No. R-17XXX
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-17XXX
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 11-12 through FY 15-16.

There were not any gas interruptions during the period of FY 11-12 through FY 15-16.

3 DAY PEAK ANALYSIS

Winter		Average	Hi	Low	Total	Firm	Cogen	LBS	BPS	GTS	IT
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	474,747	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
2013 - 2014	Jan 22	14	19	8	576,853	513,402	59	0	114	2,422	60,855
2013 - 2014	Jan 23	18	26	13	550,700	485,528	61	0	104	1,698	63,310
2013 - 2014	Jan 24	22	29	15	544,086	478,302	61	0	114	3,716	61,893
2014 - 2015	Feb 15	11	17	4	645,370	563,253	0	0	0	4,018	78,099
2014 - 2015	Feb 16	16	21	9	617,947	527,584	0	0	0	3,957	86,406
2014 - 2015	Feb 17	24	30	19	532,242	452,250	0	0	0	3,751	76,241
2015 - 2016	Feb 12	26	30	22	490,537	407,974	43	0	0	3,984	78,536
2015 - 2016	Feb 13	16	24	9	583,377	498,793	43	0	0	3,870	80,671
2015 - 2016	Feb 14	18	24	11	562,929	489,468	43	0	0	3,653	69,765

Tab 12

Docket No. R-17XXX
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 13-14 through FY 15-16 which would reflect the most current consumption behaviors of its customers. This period yielded 77 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 86.7 % 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 16,777 MCF.

The sample loses 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 66 data points and there were 64 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 652,781 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 14-16 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)
Wednesday	12/11/2013	32	33	1,089	35,937	345,621	10,473	352,303	348,620	345,945
Thursday	12/12/2013	29	36	1,296	46,656	383,330	10,648	380,473	380,736	382,575
Monday	12/16/2013	31	34	1,156	39,304	361,869	10,643	361,693	359,520	359,027
Tuesday	12/17/2013	31	34	1,156	39,304	359,059	10,561	361,693	359,520	359,027
Thursday	1/2/2014	26	39	1,521	59,319	384,574	9,861	408,643	411,103	412,706
Friday	1/3/2014	17	48	2,304	110,592	470,146	9,795	493,152	491,718	488,444
Monday	1/6/2014	26	39	1,521	59,319	400,578	10,271	408,643	411,103	412,706
Tuesday	1/7/2014	13	52	2,704	140,608	527,569	10,146	530,712	522,497	527,553
Wednesday	1/8/2014	26	39	1,521	59,319	454,741	11,660	408,643	411,103	412,706
Tuesday	1/21/2014	16	49	2,401	117,649	454,261	9,271	502,542	499,704	497,456
Wednesday	1/22/2014	14	51	2,601	132,651	513,403	10,067	521,322	515,094	516,921
Thursday	1/23/2014	18	47	2,209	103,823	485,527	10,330	483,762	483,538	479,791
Friday	1/24/2014	22	43	1,849	79,507	478,302	11,123	446,202	448,874	446,977
Monday	1/27/2014	28	37	1,369	50,653	411,075	11,110	389,863	391,052	393,221
Tuesday	1/28/2014	16	49	2,401	117,649	497,124	10,145	502,542	499,704	497,456
Wednesday	1/29/2014	20	45	2,025	91,125	492,387	10,942	464,982	466,594	463,205
Thursday	1/30/2014	27	38	1,444	54,872	422,136	11,109	399,253	401,175	403,234
Monday	2/3/2014	32	33	1,089	35,937	340,943	10,332	352,303	348,620	345,945
Thursday	2/6/2014	30	35	1,225	42,875	379,892	10,854	371,083	370,225	371,207
Friday	2/7/2014	31	34	1,156	39,304	363,342	10,687	361,693	359,520	359,027
Monday	2/10/2014	25	40	1,600	64,000	419,035	10,476	418,033	420,837	421,726
Tuesday	2/11/2014	22	43	1,849	79,507	438,956	10,208	446,202	448,874	446,977
Wednesday	2/12/2014	27	38	1,444	54,872	430,300	11,324	399,253	401,175	403,234
Tuesday	2/25/2014	32	33	1,089	35,937	360,362	10,920	352,303	348,620	345,945
Wednesday	2/26/2014	27	38	1,444	54,872	389,769	10,257	399,253	401,175	403,234
Thursday	2/27/2014	23	42	1,764	74,088	450,050	10,715	436,813	439,723	438,771
Friday	2/28/2014	22	43	1,849	79,507	440,399	10,242	446,202	448,874	446,977
Monday	3/3/2014	20	45	2,025	91,125	468,269	10,406	464,982	466,594	463,205
Tuesday	3/4/2014	28	37	1,369	50,653	408,710	11,046	389,863	391,052	393,221
Thursday	3/6/2014	30	35	1,225	42,875	372,518	10,643	371,083	370,225	371,207
Thursday	3/13/2014	30	35	1,225	42,875	377,063	10,773	371,083	370,225	371,207
Monday	3/17/2014	32	33	1,089	35,937	346,592	10,503	352,303	348,620	345,945
Monday	3/24/2014	32	33	1,089	35,937	328,314	9,949	352,303	348,620	345,945
Wednesday	3/26/2014	32	33	1,089	35,937	343,473	10,408	352,303	348,620	345,945
Tuesday	11/18/2014	28	37	1,369	50,653	350,906	9,484	389,863	391,052	393,221
Wednesday	12/31/2014	32	33	1,089	35,937	340,403	10,315	352,303	348,620	345,945
Monday	1/5/2015	29	36	1,296	46,656	348,249	9,674	380,473	380,736	382,575
Tuesday	1/6/2015	25	40	1,600	64,000	400,833	10,021	418,033	420,837	421,726
Wednesday	1/7/2015	18	47	2,209	103,823	488,236	10,388	483,762	483,538	479,791
Thursday	1/8/2015	22	43	1,849	79,507	479,237	11,145	446,202	448,874	446,977
Friday	1/9/2015	28	37	1,369	50,653	413,890	11,186	389,863	391,052	393,221
Tuesday	1/13/2015	26	39	1,521	59,319	391,385	10,036	408,643	411,103	412,706
Wednesday	1/14/2015	31	34	1,156	39,304	373,561	10,987	361,693	359,520	359,027
Friday	1/16/2015	31	34	1,156	39,304	357,367	10,511	361,693	359,520	359,027

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)
Wednesday	1/21/2015	32	33	1,089	35,937	344,596	10,442	352,303	348,620	345,945
Monday	1/26/2015	28	37	1,369	50,653	379,785	10,264	389,863	391,052	393,221
Tuesday	1/27/2015	27	38	1,444	54,872	407,871	10,733	399,253	401,175	403,234
Wednesday	1/28/2015	29	36	1,296	46,656	397,632	11,045	380,473	380,736	382,575
Friday	1/30/2015	27	38	1,444	54,872	396,701	10,440	399,253	401,175	403,234
Monday	2/2/2015	28	37	1,369	50,653	391,048	10,569	389,863	391,052	393,221
Tuesday	2/3/2015	28	37	1,369	50,653	395,063	10,677	389,863	391,052	393,221
Thursday	2/5/2015	23	42	1,764	74,088	426,585	10,157	436,813	439,723	438,771
Friday	2/6/2015	31	34	1,156	39,304	393,873	11,584	361,693	359,520	359,027
Monday	2/9/2015	30	35	1,225	42,875	365,974	10,456	371,083	370,225	371,207
Thursday	2/12/2015	27	38	1,444	54,872	399,536	10,514	399,253	401,175	403,234
Friday	2/13/2015	22	43	1,849	79,507	454,929	10,580	446,202	448,874	446,977
Tuesday	2/17/2015	24	41	1,681	68,921	452,250	11,030	427,423	430,377	430,384
Wednesday	2/18/2015	25	40	1,600	64,000	420,596	10,515	418,033	420,837	421,726
Thursday	2/19/2015	12	53	2,809	148,877	539,717	10,183	540,102	529,706	538,906
Friday	2/20/2015	16	49	2,401	117,649	552,584	11,277	502,542	499,704	497,456
Monday	2/23/2015	19	46	2,116	97,336	463,598	10,078	474,372	475,163	471,409
Tuesday	2/24/2015	24	41	1,681	68,921	445,516	10,866	427,423	430,377	430,384
Thursday	2/26/2015	29	36	1,296	46,656	379,463	10,541	380,473	380,736	382,575
Friday	2/27/2015	25	40	1,600	64,000	405,365	10,134	418,033	420,837	421,726
Thursday	3/5/2015	21	44	1,936	85,184	421,654	9,583	455,592	457,831	455,092
Friday	3/6/2015	23	42	1,764	74,088	423,507	10,084	436,813	439,723	438,771
Monday	1/4/2016	21	44	1,936	85,184	407,940	9,271	455,592	457,831	455,092
Tuesday	1/5/2016	27	38	1,444	54,872	398,646	10,491	399,253	401,175	403,234
Monday	1/11/2016	31	34	1,156	39,304	334,881	9,849	361,693	359,520	359,027
Wednesday	1/13/2016	28	37	1,369	50,653	379,941	10,269	389,863	391,052	393,221
Tuesday	1/19/2016	26	39	1,521	59,319	430,686	11,043	408,643	411,103	412,706
Thursday	1/21/2016	31	34	1,156	39,304	361,668	10,637	361,693	359,520	359,027
Friday	1/22/2016	27	38	1,444	54,872	397,773	10,468	399,253	401,175	403,234
Wednesday	2/10/2016	31	34	1,156	39,304	355,015	10,442	361,693	359,520	359,027
Thursday	2/11/2016	24	41	1,681	68,921	435,736	10,628	427,423	430,377	430,384
Friday	2/12/2016	26	39	1,521	59,319	419,340	10,752	408,643	411,103	412,706
Thursday	2/18/2016	32	33	1,089	35,937	345,555	10,471	352,303	348,620	345,945
Count	77		65	4,225	274,625	409,984	10,490	652,781	601,068	764,165

Firm Sendout Projection Based Data From 14-16
Data for Daily Temperatures <= 32 Degrees Fahrenheit

R Squared	Change	Student's T	Degrees of Freedom	Critical Value	@ 97.5% Significant
0.866811	0.866811	22.093158	75	1.99	Yes
0.869860	0.003050	1.316890	74	1.98	No
0.871898	0.002038	1.077546	73	1.98	No

Degrees of Freedom	75	74	73
97.5% Significance Level	1.99	1.98	1.98
95.0% Significance Level	1.66	1.66	1.66

LinearProjection at Zero Degrees Fahrenheit	652,781	Mcf
Linear Projection at 15 Degrees Fahrenheit	511,932	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 * X1u2Coeff) + (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	345,621	352,303	(6,682)	44,651,279	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
2	33	340,943	352,303	(11,360)	129,045,112	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
3	33	360,362	352,303	8,059	64,943,509	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
4	33	346,592	352,303	(5,711)	32,617,363	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
5	33	328,314	352,303	(23,989)	575,479,858	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
6	33	343,473	352,303	(8,830)	77,971,748	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
7	33	340,403	352,303	(11,900)	141,602,298	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
8	33	344,596	352,303	(7,707)	59,394,521	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
9	33	345,555	352,303	(6,748)	45,535,759	(6)	38	3,392	6,755	345,548	359,058	333,547	371,059	314,791	389,815
10	34	361,869	361,693	176	30,945	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
11	34	359,059	361,693	(2,634)	6,938,425	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
12	34	363,342	361,693	1,648	2,717,382	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
13	34	373,561	361,693	11,868	140,841,143	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
14	34	357,367	361,693	(4,327)	18,718,678	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
15	34	393,873	361,693	32,180	1,035,523,139	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
16	34	334,881	361,693	(26,812)	718,903,945	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
17	34	361,668	361,693	(26)	652	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
18	34	355,015	361,693	(6,679)	44,602,840	(5)	26	3,077	6,127	355,566	367,820	342,937	380,449	324,181	399,205
19	35	379,892	371,083	8,809	77,606,714	(4)	17	2,791	5,558	365,525	376,641	352,327	389,839	333,571	408,595
20	35	372,518	371,083	1,435	2,059,177	(4)	17	2,791	5,558	365,525	376,641	352,327	389,839	333,571	408,595
21	35	377,063	371,083	5,980	35,760,198	(4)	17	2,791	5,558	365,525	376,641	352,327	389,839	333,571	408,595
22	35	365,974	371,083	(5,109)	26,097,357	(4)	17	2,791	5,558	365,525	376,641	352,327	389,839	333,571	408,595
23	36	383,330	380,473	2,857	8,162,765	(3)	10	2,545	5,067	375,406	385,540	361,717	399,229	342,961	417,985
24	36	348,249	380,473	(32,224)	1,038,379,261	(3)	10	2,545	5,067	375,406	385,540	361,717	399,229	342,961	417,985
25	36	397,632	380,473	17,159	294,439,753	(3)	10	2,545	5,067	375,406	385,540	361,717	399,229	342,961	417,985
26	36	379,463	380,473	(1,010)	1,020,284	(3)	10	2,545	5,067	375,406	385,540	361,717	399,229	342,961	417,985
27	37	411,075	389,863	21,212	449,954,352	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
28	37	408,710	389,863	18,847	355,214,214	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
29	37	350,906	389,863	(38,957)	1,517,629,972	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
30	37	413,890	389,863	24,027	577,308,189	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
31	37	379,785	389,863	(10,078)	101,563,898	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
32	37	391,048	389,863	1,185	1,404,317	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
33	37	395,063	389,863	5,200	27,039,887	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
34	37	379,941	389,863	(9,922)	98,443,434	(2)	5	2,349	4,679	385,184	394,541	371,107	408,619	352,351	427,375
35	38	422,136	399,253	22,883	523,640,827	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
36	38	430,300	399,253	31,047	963,937,632	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
37	38	389,769	399,253	(9,484)	89,942,494	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
38	38	407,871	399,253	8,618	74,267,980	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
39	38	396,701	399,253	(2,551)	6,510,014	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
40	38	399,536	399,253	284	80,485	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
41	38	398,646	399,253	(607)	368,310	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
42	38	397,773	399,253	(1,480)	2,190,876	(1)	1	2,220	4,420	394,833	403,673	380,497	418,009	361,741	436,765
43	39	384,574	408,643	(24,069)	579,303,675	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155
44	39	400,578	408,643	(8,065)	65,039,840	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155
45	39	454,741	408,643	46,098	2,125,050,668	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155

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
46	39	391,385	408,643	(17,258)	297,842,303	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155
47	39	430,686	408,643	22,043	485,884,207	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155
48	39	419,340	408,643	10,697	114,432,459	(0)	0	2,167	4,314	404,328	412,957	389,887	427,399	371,131	446,155
49	40	419,035	418,033	1,003	1,005,500	1	1	2,196	4,373	413,659	422,406	399,277	436,789	380,520	455,545
50	40	400,833	418,033	(17,199)	295,819,631	1	1	2,196	4,373	413,659	422,406	399,277	436,789	380,520	455,545
51	40	420,596	418,033	2,564	6,572,248	1	1	2,196	4,373	413,659	422,406	399,277	436,789	380,520	455,545
52	40	405,365	418,033	(12,668)	160,472,450	1	1	2,196	4,373	413,659	422,406	399,277	436,789	380,520	455,545
53	41	452,250	427,423	24,827	616,382,627	2	3	2,305	4,590	422,832	432,013	408,666	446,179	389,910	464,935
54	41	445,516	427,423	18,093	327,360,977	2	3	2,305	4,590	422,832	432,013	408,666	446,179	389,910	464,935
55	41	435,736	427,423	8,314	69,114,566	2	3	2,305	4,590	422,832	432,013	408,666	446,179	389,910	464,935
56	42	450,050	436,813	13,237	175,228,076	3	8	2,483	4,944	431,868	441,757	418,056	455,569	399,300	474,325
57	42	426,585	436,813	(10,228)	104,610,161	3	8	2,483	4,944	431,868	441,757	418,056	455,569	399,300	474,325
58	42	423,507	436,813	(13,305)	177,032,170	3	8	2,483	4,944	431,868	441,757	418,056	455,569	399,300	474,325
59	43	478,302	446,202	32,100	1,030,381,790	4	15	2,716	5,409	440,794	451,611	427,446	464,959	408,690	483,715
60	43	438,956	446,202	(7,247)	52,517,676	4	15	2,716	5,409	440,794	451,611	427,446	464,959	408,690	483,715
61	43	440,399	446,202	(5,803)	33,679,909	4	15	2,716	5,409	440,794	451,611	427,446	464,959	408,690	483,715
62	43	479,237	446,202	33,035	1,091,303,257	4	15	2,716	5,409	440,794	451,611	427,446	464,959	408,690	483,715
63	43	454,929	446,202	8,727	76,161,503	4	15	2,716	5,409	440,794	451,611	427,446	464,959	408,690	483,715
64	44	421,654	455,592	(33,938)	1,151,813,475	5	24	2,992	5,958	449,634	461,550	436,836	474,348	418,080	493,105
65	44	407,940	455,592	(47,653)	2,270,761,503	5	24	2,992	5,958	449,634	461,550	436,836	474,348	418,080	493,105
66	45	492,387	464,982	27,405	751,017,854	6	34	3,300	6,571	458,412	471,553	446,226	483,738	427,470	502,495
67	45	468,269	464,982	3,287	10,805,321	6	34	3,300	6,571	458,412	471,553	446,226	483,738	427,470	502,495
68	46	463,598	474,372	(10,774)	116,088,416	7	47	3,631	7,230	467,142	481,603	455,616	493,128	436,860	511,884
69	47	485,527	483,762	1,765	3,114,693	8	62	3,980	7,926	475,836	491,688	465,006	502,518	446,250	521,274
70	47	488,236	483,762	4,474	20,018,426	8	62	3,980	7,926	475,836	491,688	465,006	502,518	446,250	521,274
71	48	470,146	493,152	(23,006)	529,279,647	9	78	4,343	8,648	484,504	501,800	474,396	511,908	455,640	530,664
72	49	454,261	502,542	(48,281)	2,331,055,570	10	97	4,716	9,391	493,151	511,933	483,786	521,298	465,030	540,054
73	49	497,124	502,542	(5,418)	29,354,792	10	97	4,716	9,391	493,151	511,933	483,786	521,298	465,030	540,054
74	49	552,584	502,542	50,042	2,504,164,748	10	97	4,716	9,391	493,151	511,933	483,786	521,298	465,030	540,054
75	51	513,403	521,322	(7,919)	62,708,374	12	141	5,485	10,923	510,399	532,244	502,566	540,078	483,810	558,834
76	52	527,569	530,712	(3,143)	9,877,127	13	165	5,878	11,705	519,007	542,417	511,956	549,468	493,200	568,224
77	53	539,717	540,102	(385)	148,040	14	192	6,275	12,496	527,606	552,597	521,346	558,858	502,590	577,614
	65		652,781	(652,781)	426,122,839,893	26	669	11,201	22,305	630,476	675,086	634,025	671,537	615,269	690,293
Tot/Avg	39	409,984	409,984		27,087,944,664		1,999								

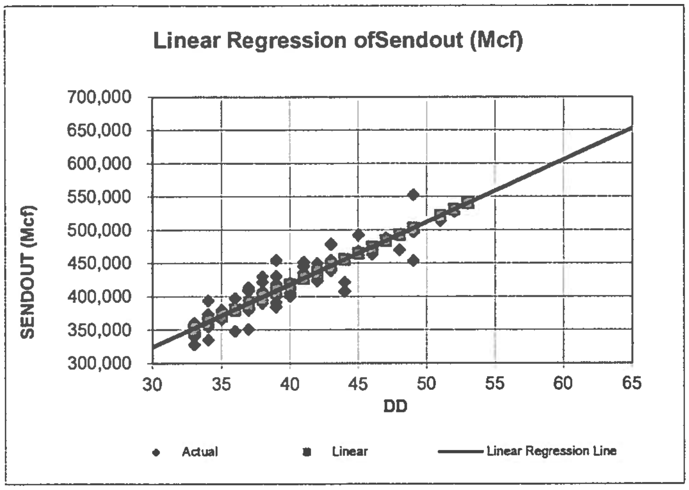
t = 1.99

Xm = 39				
Population Variance=	351,791,489			
			Upper Range	Lower Range
Population Standard Deviation of Regression =	18,756	1s	428,740	391,228
		2s	447,496	372,472
Standard error of sendout projection	19,005			
T-factor	1.99			
(T factor) * (Std error of projection)	37,844			

Regression Results
Winter 14-16
Based On Data for Daily Temperatures <= 32 Degrees Fahrenheit

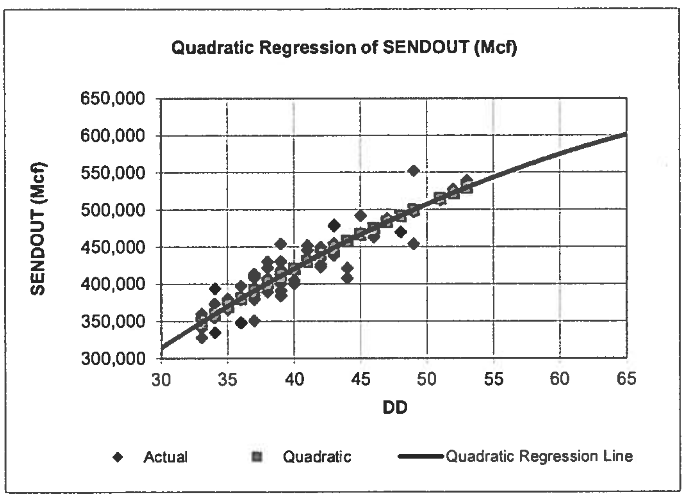
Regression Output:			**Quadratic**			**Cubic**			
Regression Output:			Regression Output:			Regression Output:			
Constant		42,436	Constant		(120,016)	Constant		(1,182,272)	
Std Err of Y Est		16,777	Std Err of Y Est		124,484	Std Err of Y Est		993,622	
R Squared		0.8668	R Squared		1	R Squared		1	
No. of Observations		77	No. of Observations		77	No. of Observations		77	
Degrees of Freedom		75	Degrees of Freedom		74	Degrees of Freedom		73	
				X	X^2		X	X^2	X^3
X Coefficient(s)	9,390		X Coefficient(s)	17405.6938	(97)	X Coefficient(s)	95,421	(1,984)	15
Std Err of Coef.	425		Std Err of Coef.	6101.5670	74	Std Err of Coef.	72,657	1,753	14
Zero Degree Temp Sendout		652,781			601,068			764,165	
DD	65								

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 14-16



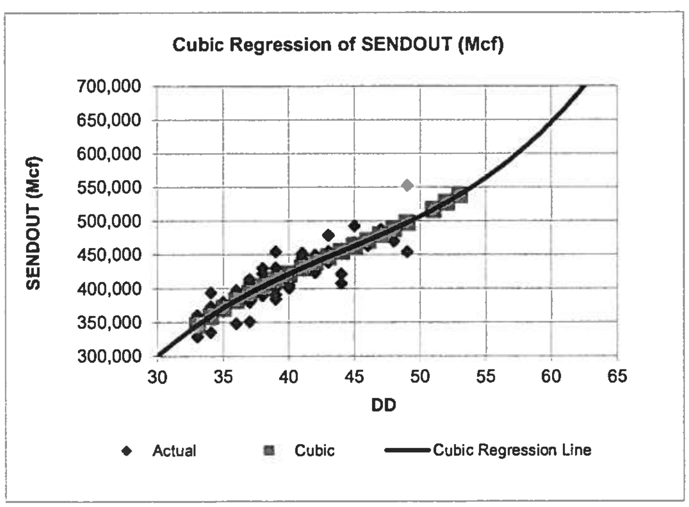
Linear Regression Output

Constant		42,436
Std. Error of Y Estimate		16,777
R Squared		0.867
Number of Observations		77
Degrees of Freedom		75
	X	
X Coefficient	9390	
Std. Err. Of Coefficeint	425	



Quadratic Regression Output

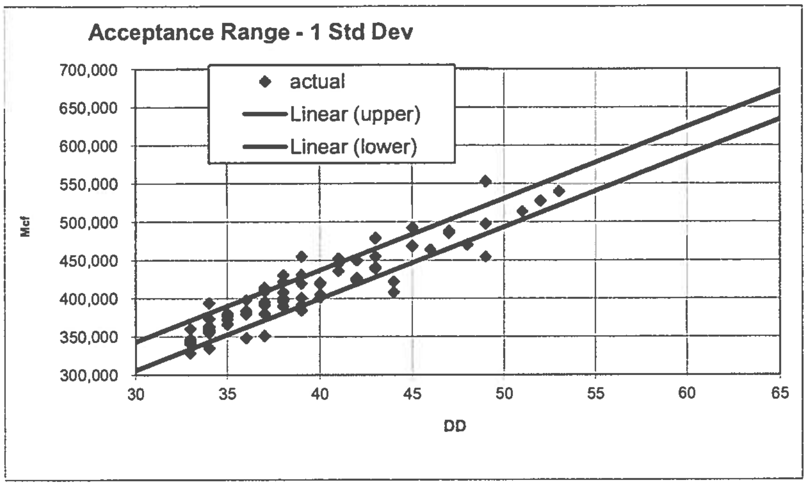
Constant		(120,016)
Std. Error of Y Estimate		124,484
R Squared		0.870
Number of Observations		77
Degrees of Freedom		74
	X	X ^ 2
X Coefficient	17,406	(97)
Std. Err. Of Coefficeint	6,102	74



Cubic Regression Output

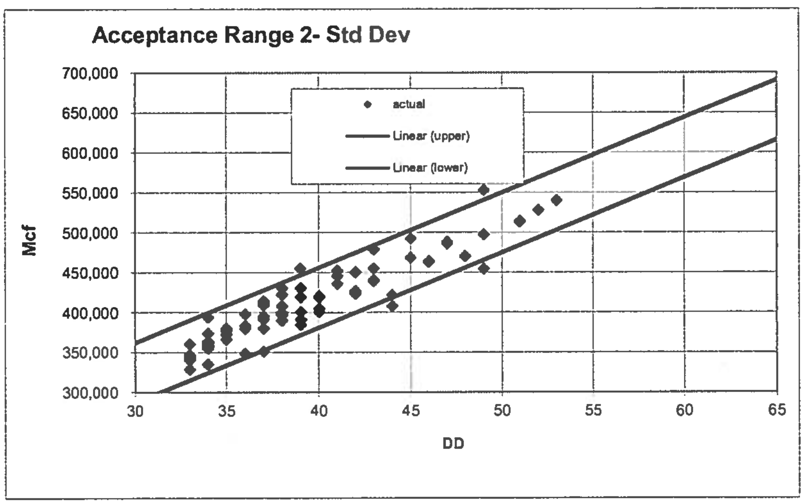
Constant		(1,182,272)	
Std. Error of Y Estimate		993,622	
R Squared		0.872	
Number of Observations		77	
Degrees of Freedom		73	
	X	X ^ 2	X ^ 3
X Coefficient	95421	(1984)	15
Std. Err. Of Coefficeint	72657	1753	14

Regression Chart Analysis
Based Upon Data For Temperatures Of <=32 Degrees F.
Winters 14-16



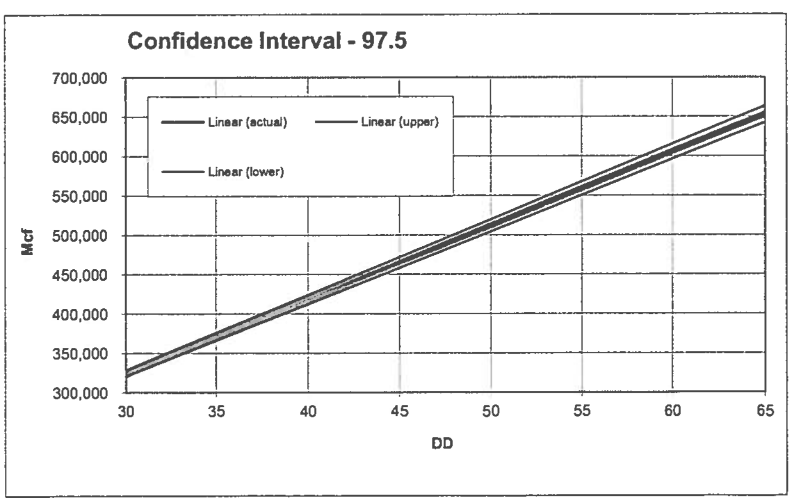
Acceptance Range @ 1 Standard Deviation

Regression Squared	351,791,489
Regression	18,756
Upper Range 1sd	428,740
Lower Range 1sd	391,228



Acceptance Range @ 2 Standard Deviation

Regression Squared	351,791,489
Regression	18,756
Upper Range 2sd	447,496
Lower Range 2sd	372,472



Confidence Interval: 97.5%

Regression Squared	351,791,489
Standard error of sendout projection	19,005
X Mean	39
T Distribution	1.99

ICF INTERNATIONAL

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

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- 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

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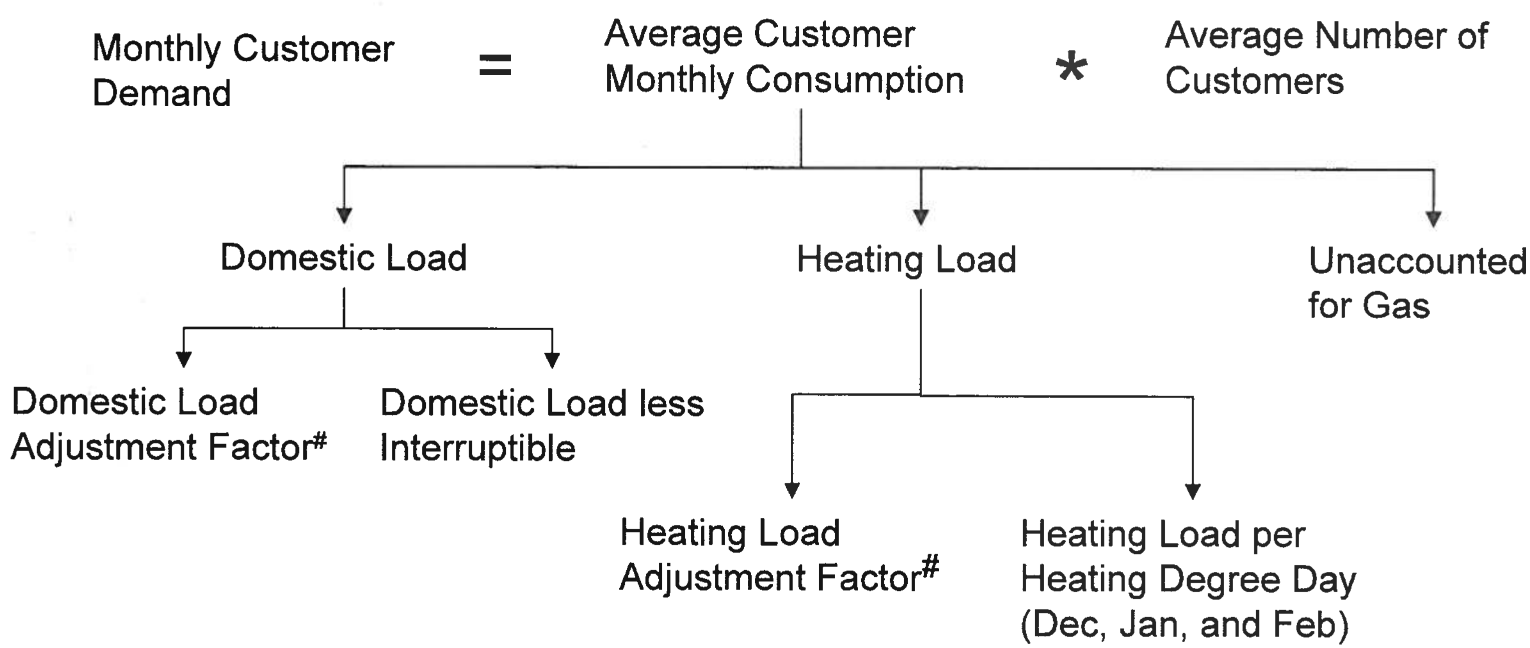
- PGW uses a combination of inputs into demand estimation
  - Historical demand trends for each customer class
  - Customer surveys
  - End use studies – appliance characteristics
  - Judgment of system operators
- Demand is related to temperature through heating degree days (HDD)
- Capacity planning 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

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:

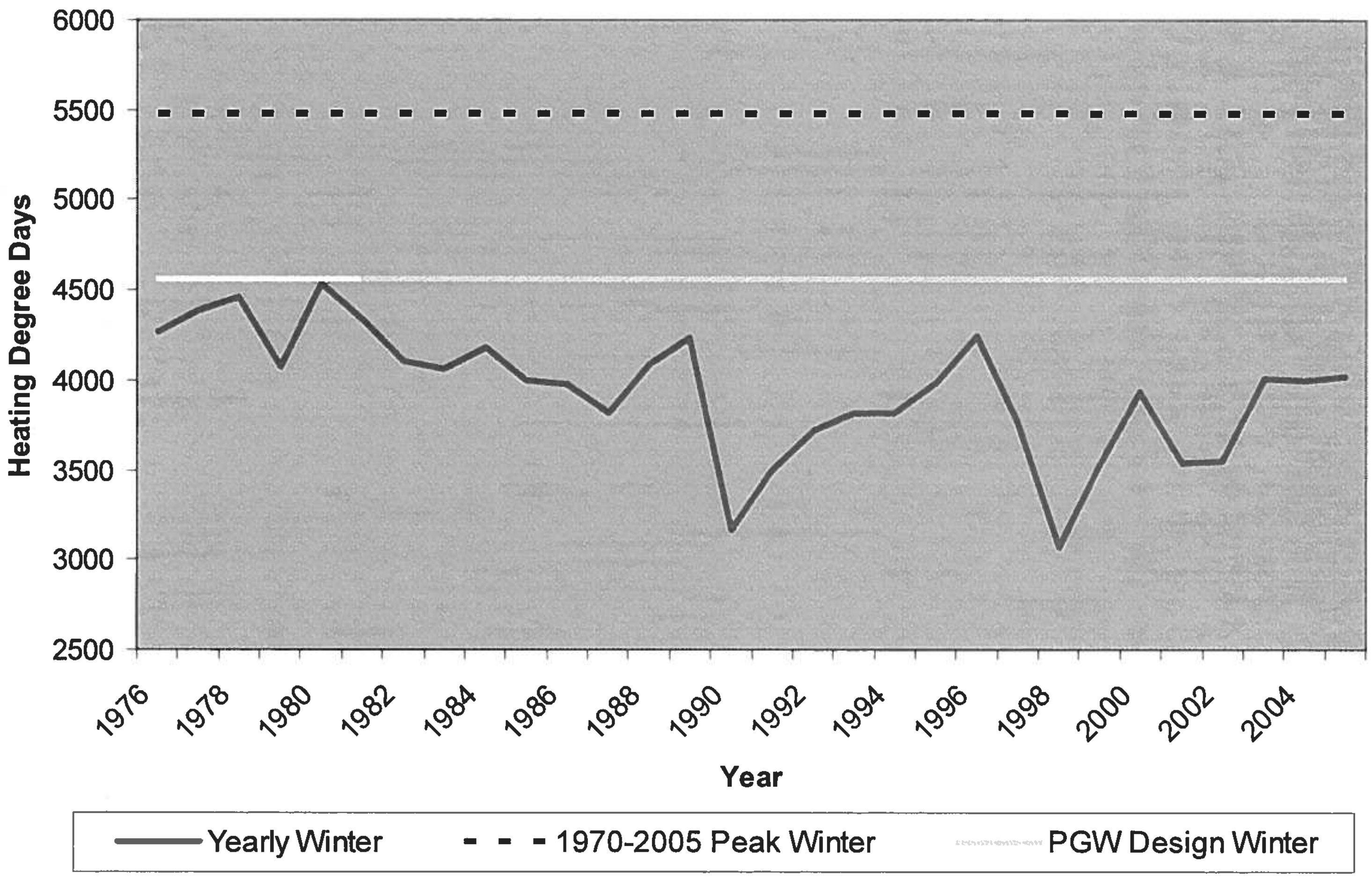
[a] It is coefficient of variation, calculated as (sample standard deviation/sample mean)*100.

[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.

PGW Design Winter Heating Degree Days

Philadelphia Winter Heating Degree Days



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

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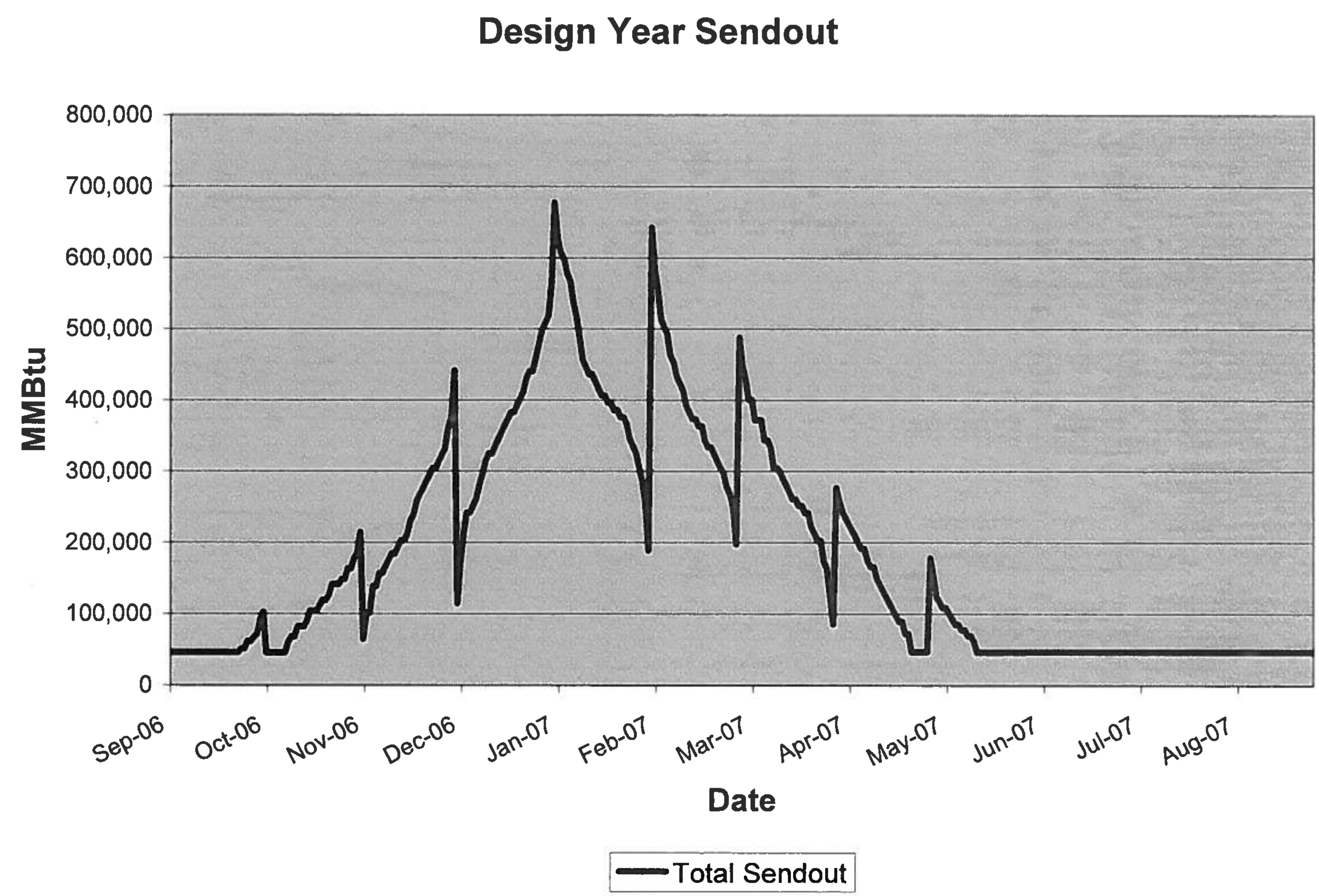
- PGW's approach remains essentially the same as was reviewed in the previous study.
- PGW's approach yields a forecast of design day and design winter that are reasonable estimations.
  - The design conditions are below "theoretical" worst case (which could yield higher than necessary investments)
  - 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

ICF INTERNATIONAL

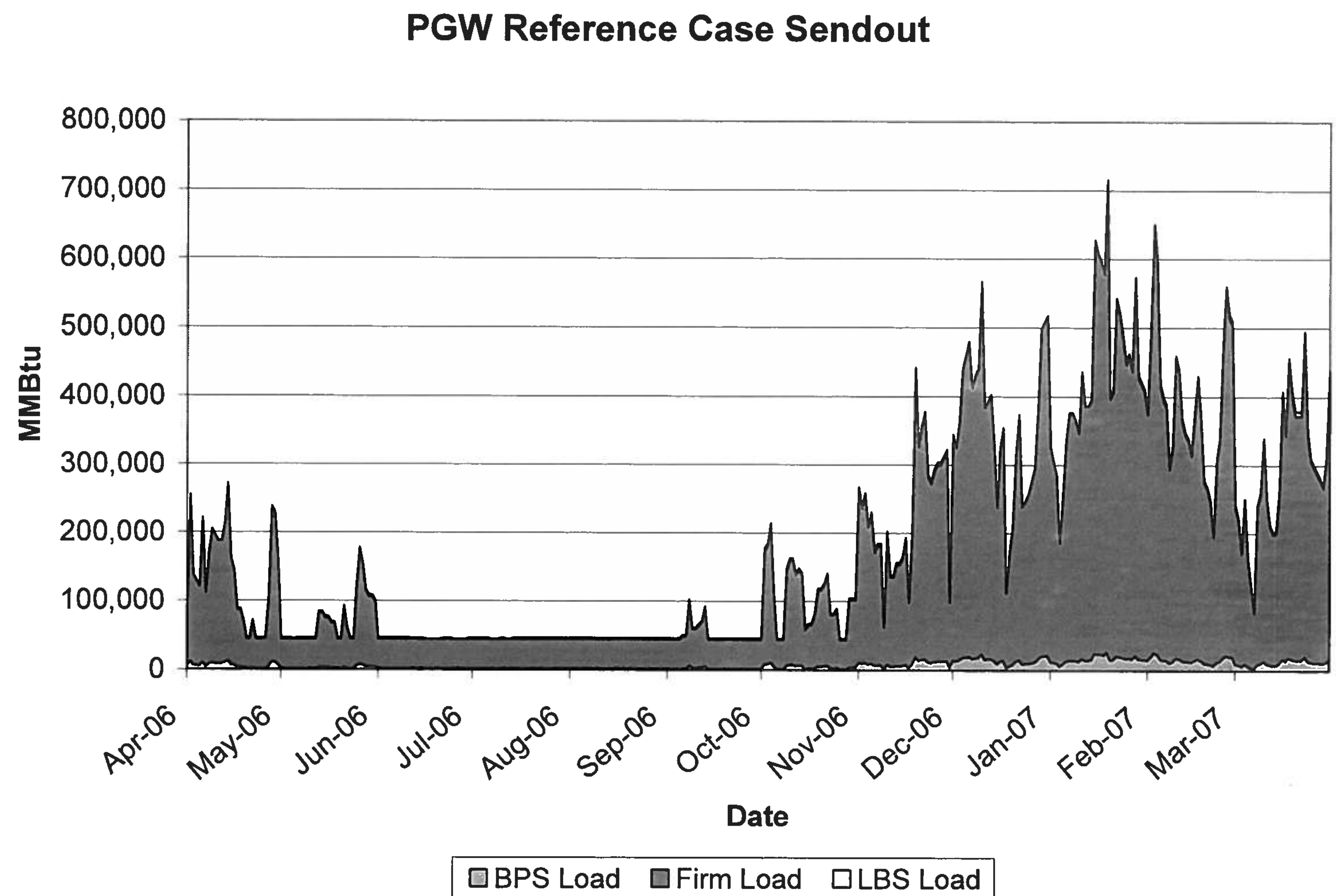
- First step is to use design winter parameters for 2006-2007 provided by PGW for its PGC filings with the Philadelphia Gas Commission.
  - These data are from September through August and in the form of load duration curves for each month.
- Data were converted to April through March and randomized 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

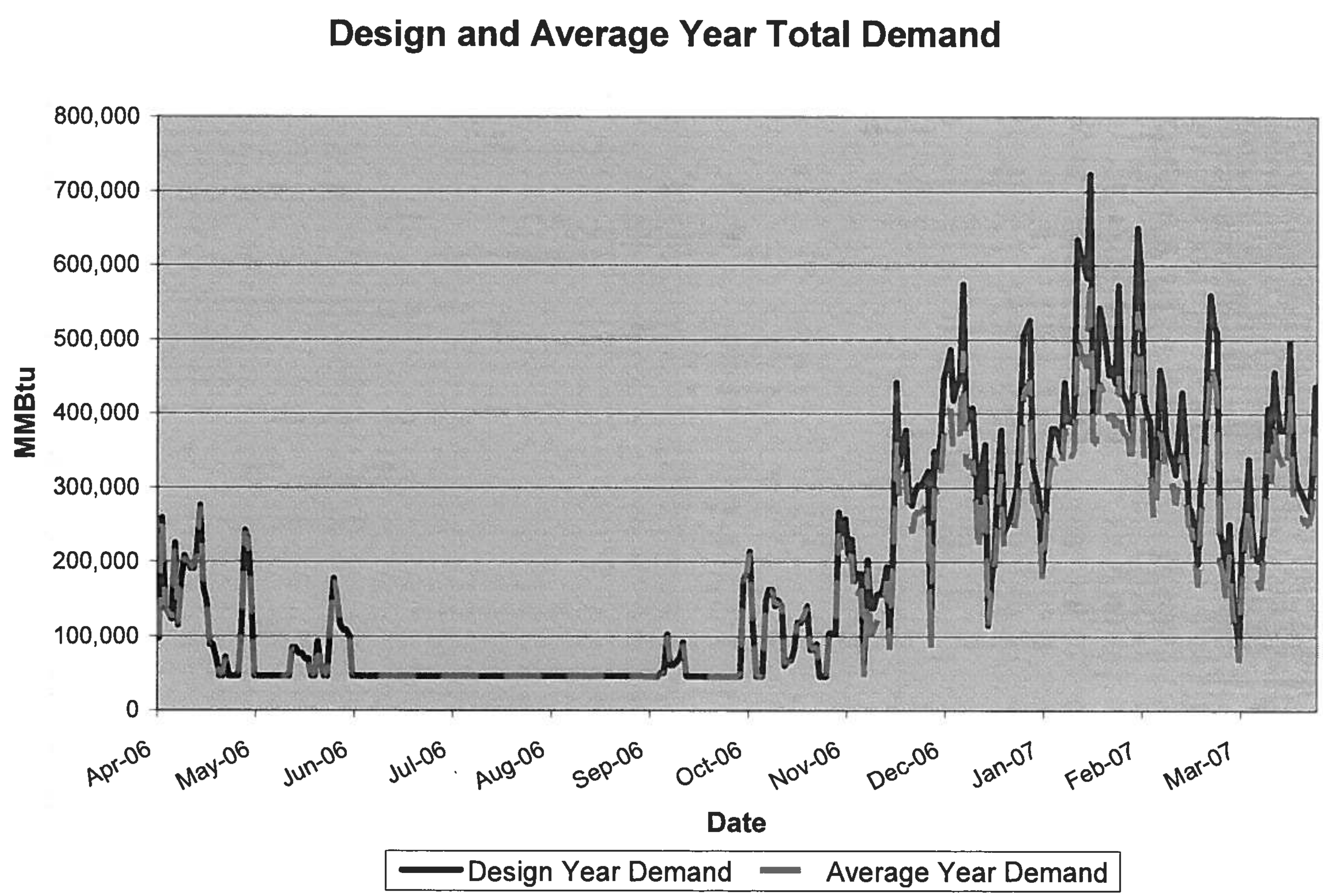


Passion. Expertise. Results.

Sendout Reordered and Randomized – April 1 to March 31

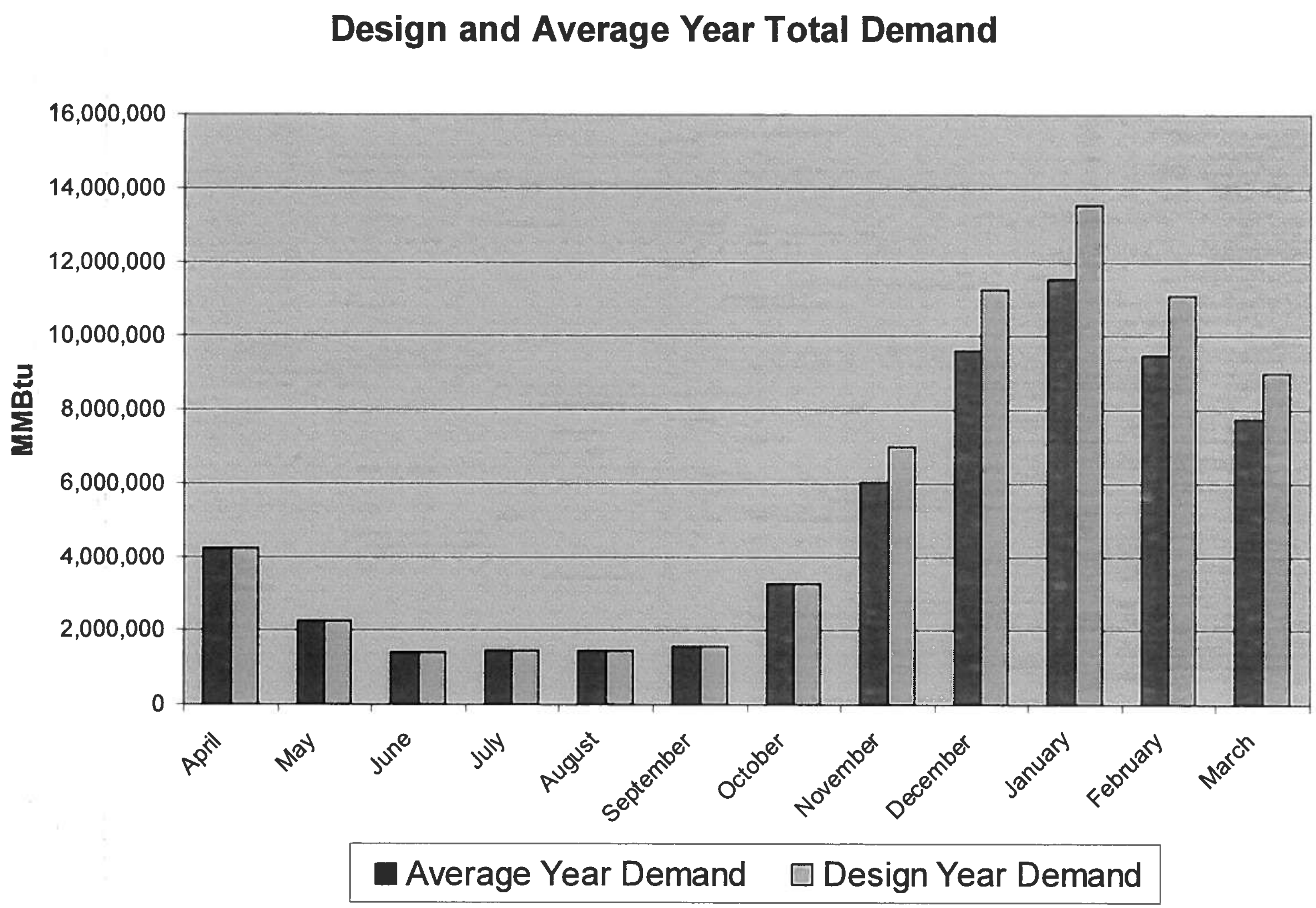


Demand Patterns Modeled Consistent with Gas Prices



Passion. Expertise. Results.

Design and Average Winter Demand -- Simplified



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

- 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

ICF INTERNATIONAL

- 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

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

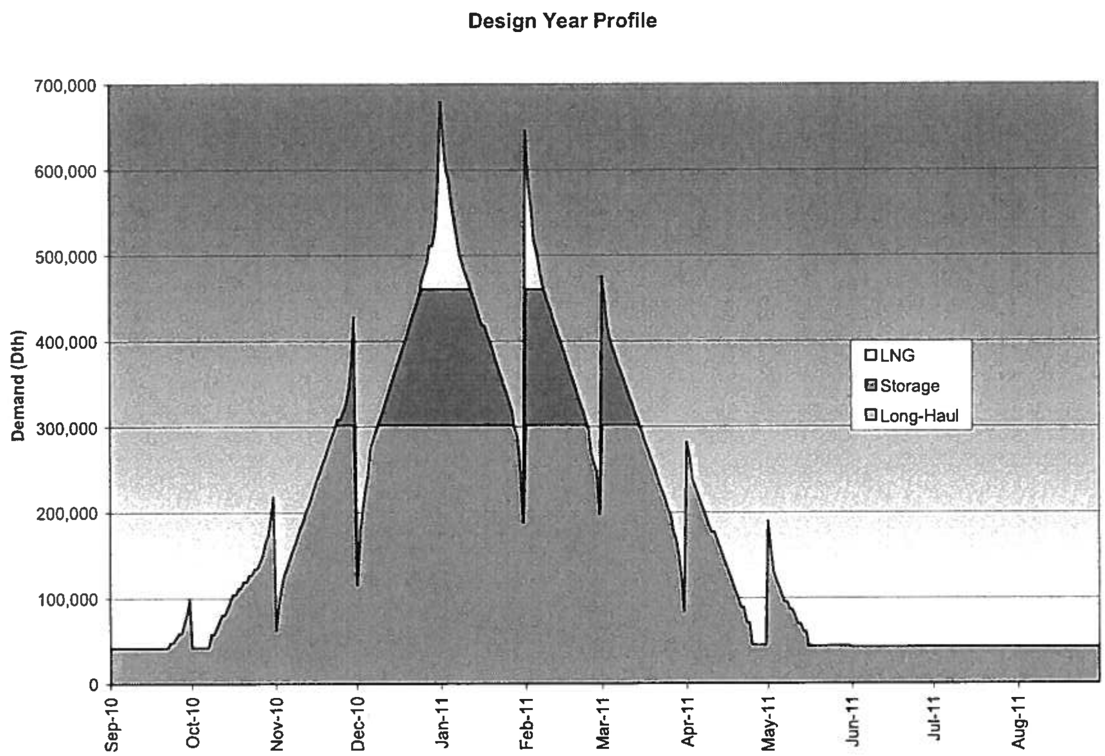
Long-Haul Transport	Capacity (Dth)	Estimated WACOG ($/Dth)
Tetco CDS	75,000	$6.145
Tetco FT-1	59,822	$6.130
Transco FT	167,179	$5.827

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-17XXX

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 2016
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	2016	26,541,391	24,255,062	106.1%	25,742,827	96,731	0	25,839,558	1,197	(700,636)
FEBRUARY		21,760,564	28,266,729	107.3%	30,320,447	95,271	7,561	30,423,278	6,382	8,669,097
MARCH		13,895,507	20,633,034	107.3%	22,132,127	93,915	4,902	22,230,943	0	8,335,436
APRIL		9,593,675	13,050,528	111.8%	14,588,595	89,738	0	14,678,333	0	5,084,658
MAY		9,541,183	8,232,518	116.7%	9,606,864	90,134	0	9,696,998	0	155,815
JUNE		5,887,695	4,666,423	116.7%	5,445,441	89,807	0	5,535,248	0	(352,447)
JULY		6,215,584	3,073,877	108.1%	3,322,753	90,851	0	3,413,604	8,769	(2,793,211)
AUGUST *		6,675,834	2,756,457	101.5%	2,798,172	90,851	0	2,889,023	0	(3,786,811)
SEPTEMBER		6,304,036	3,457,095	101.5%	3,509,413	91,214	0	3,600,627	0	(2,703,409)
OCTOBER*		7,755,475	5,070,159	101.4%	5,138,688	91,214	0	5,229,902	0	(2,525,573)
NOVEMBER*		14,028,425	10,825,976	101.2%	10,954,606	91,214	0	11,045,819	1,431	(2,981,174)
DECEMBER*		27,056,975	23,143,420	101.2%	23,418,400	91,214	7,493	23,517,107	0	(3,539,868)
Totals		155,256,344	147,431,278		156,978,332	1,102,152	19,956	158,100,439	17,780	2,861,876

*Load Balancing Revenue-Estimated

STATEMENT OF RECONCILIATION
UNIVERSAL SERVICES & ENERGY CONSERVATION SURCHARGE
CALENDAR YEAR 2016

Month		USC Applicable Volumes	USC Charge	USC Revenue Billed	USC Expenses	Monthly Over/(Under) Recovery	Cumulative Over/(Under) Recovery
December 2015							($5,994,301)
January 2016	Actual	7,019,199	$ 1.0669	$ 7,488,784	$ 12,271,685	$ (4,782,901)	($10,777,202)
February	Actual	8,466,423	$ 1.0669	$ 9,032,826	$ 12,852,293	$ (3,819,467)	($14,596,669)
March	Actual	6,231,280	$ 1.2174	$ 7,585,960	$ 10,501,395	$ (2,915,434)	($17,512,103)
April	Actual	4,094,452	$ 1.3679	$ 5,600,801	$ 7,089,999	$ (1,489,197)	($19,001,301)
May	Actual	2,599,218	$ 1.3679	$ 3,555,470	$ 2,824,027	$ 731,442	($18,269,858)
June	Actual	1,554,784	$ 1.4364	$ 2,233,292	$ 512,417	$ 1,720,875	($16,548,984)
July	Actual	1,090,333	$ 1.5048	$ 1,640,734	$ (416,323)	$ 2,057,057	($14,491,927)
August	Actual	997,202	$ 1.5048	$ 1,500,589	$ 317,617	$ 1,182,972	($13,308,955)
September	Actual	1,071,555	$ 1.5104	$ 1,618,477	$ (2,641,360)	$ 4,259,836	($9,049,119)
October	Actual	1,401,686	$ 1.5160	$ 2,124,956	$ (1,818,406)	$ 3,943,362	($5,105,757)
November	Actual	2,945,088	$ 1.5160	$ 4,464,753	$ 2,590,760	$ 1,873,993	($3,231,764)
December	Actual	6,044,721	$ 1.4103	$ 8,524,869	$ 8,434,399	$ 90,470	($3,141,294)

USC Expenses	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Total
ELIRP Expense	$ 627,513	$ 614,085	$ 577,807	$ 773,096	$ 616,300	$ 639,508	$ 735,507	$ 1,574,432	$ 4,070	$ 3,253	$ 718,095	$ 1,262,122	$ 8,145,788
ELIRP Labor	$ 11,284	$ 9,149	$ 9,212	$ 12,251	$ 9,325	$ 10,614	$ 14,025	$ 13,193	$ 9,245	$ 6,710	$ 8,205	$ 9,915	$ 123,128
CRP Discount	$ 10,196,817	$ 10,828,112	$ 8,489,760	$ 4,982,892	$ 1,114,289	$ (1,096,436)	$ (2,026,795)	$ (2,160,228)	$ (1,982,820)	$ (1,220,808)	$ 2,207,684	$ 7,322,973	$ 36,655,438
CRP Forgiveness	$ 781,302	$ 718,458	$ 867,149	$ 934,553	$ 855,603	$ 825,567	$ 768,032	$ 801,053	$ (764,938)	$ (734,013)	$ (625,108)	$ (676,546)	$ 3,751,112
Senior Citizen Discount	$ 654,769	$ 682,489	$ 557,467	$ 387,207	$ 228,510	$ 133,164	$ 92,908	$ 89,167	$ 93,084	$ 126,452	$ 281,884	$ 515,935	$ 3,843,037
Bad Debt Expense Offset*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 12,271,685	$ 12,852,293	$ 10,501,395	$ 7,089,999	$ 2,824,027	$ 512,417	$ (416,323)	$ 317,617	$ (2,641,360)	$ (1,818,406)	$ 2,590,760	$ 8,434,399	$ 52,518,503

CRP Participation	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
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*	57,112	56,006	55,435	56,823	55,569	51,691	50,914	51,071	50,045	49,664	49,558	49,321
CRP Under(Over) Participation	26,888	27,994	28,565	27,177	28,431	32,309	33,086	32,929	33,955	34,336	34,442	34,679
Average Shortfall Per CRP Participant												
CRP Discount	$ 10,196,817	$ 10,828,112	$ 8,489,760	$ 4,982,892	$ 1,114,289	$ (1,096,436)	$ (2,026,795)	$ (2,160,228)	$ (1,982,820)	$ (1,220,808)	$ 2,207,684	$ 7,322,973
Actual Participation Rate	57,112	56,006	55,435	56,823	55,569	51,691	50,914	51,071	50,045	49,664	49,558	49,321
Average Shorfall per CRP Participai	$ 179	$ 193	$ 153	$ 88	$ 20	$ (21)	$ (40)	$ (42)	$ (40)	$ (25)	$ 45	$ 148
Shortfall*	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Bad Debt Expense Offs 7.1%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

Tab 15

Docket No. R-17XXX
Item 53.65 (1)

Philadelphia Gas Works

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.