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September 14, 2001

Via Hand-Delivery

K. David Waddell
Executive Secretary
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-0505

Re: Petition of Chattanooga Gas Company for Approval of Tariff Establishing Experimental Fixed Rate PGA Rider; Docket No. 01-00761; Supplemental Responses to Data Requests

Dear Mr. Waddell:

Enclosed you will find the original and thirteen (13) copies of Chattanooga Gas Company's supplemental responses to the Staff's data requests. These responses include the supplemental information and the prior information, therefore they supercede the filing made on September 11.

Sincerely,

D. Billye Sanders

D. Billye Sanders

DBS:lmb
Enclosures
cc: Hal Novak
Earl Burton
Archie Hickerson
Tim Phillips, Esq., Consumer Advocate Division

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CHATTANOOGA GAS COMPANY
Experimental Fixed Rate PGA (Docket 01-00761)
Tennessee Regulatory Authority Staff
Data Request No. 1

Item 1
The Company discusses the risk premium and lists it in your example as $1.24 per DT. Per Brian Toole's testimony (Line 12-14, page 5), "the Company considers all of the risks for this tariff that it feels it will be required to absorb over the plan year." What are those risks? Discuss **in detail,** with backup schedules, how the Company evaluated each of the risks to arrive at $1.24.

Response:
The proposed Fixed Rate PGA proposal requires a strong element of trust and cooperation between the entity that purchases the gas and Chattanooga Gas Company, because it is the gas that is delivered to the end-use customers that is guaranteed a fixed price rather than the gas delivered to the utility. This requires Chattanooga to timely and accurately report its daily sales to the purchasing entity.

Another item, which affects this proposal, is the interruptible demand, and the company's control over it. CGC's interruptible customers' transported and consumed volumes vary through the month. Since interruptible and industrial customers will still be covered under the ACA and PBR, their volumes will have to be managed separately. In addition to the ACA and PBR issues, swings in deliveries will have an affect on storage levels and gas costing, since withdrawals are charged out at weighted cost of gas and injections are entered at the cost of flowing gas. The company's ability under regulation to control these swings is fairly minimal.

Because such a strong tie to the accounting records is required from this type of arrangement and the need to manage the interruptible customers separately, the Company decided that the best course of action would be for CGC's gas trading affiliate, Sequent Energy Management, to procure the gas and take the related risk for pricing, instead of seeking bids for this service from a third party supplier.

Because the Company could not take bids on this service, we committed ourselves to be the low-cost provider of similar fixed rate arrangements in Georgia's deregulated market in order to gain acceptance and approval for this tariff from the TRA. We therefore determined a ceiling rate that would achieve this goal would be approximately $0.66 per Ccf based on the pricing of 12 month fixed rate plans in Georgia for the month of August 2001. The Risk Premium component was then computed by taking this low-cost rate to be offered, and subtracting the other identified costsi n the Fixed Rate PGA formula. After reviewing the risk premium of approximately $ 1.24 per dekatherm, Sequent Energy Management decided that this rate was acceptable for the inherent risk in the Fixed Rate PGA tariff proposal. This risk includes unpredictable variances in weather, sales, number of customers, gas spot markets, effect of industrial demands on the system, storage usage, pipeline transportation rates, pipeline capacity rates, affects of revenue swings on the companies projection of earnings, and other variables not yet identified. Affects created by natural disasters such as earthquakes, tornado, hurricanes, and acts of terrorism have not been accounted for in this price.

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Item 2
You state that the Company did not take bids from any other suppliers (excepting Sequent Energy Management, your affiliate) for the Fixed Rate PGA Tariff price offering. The reason given was that you did not know "any suppliers who would be either willing or capable of managing the complete usage risk needs for a distribution company's residential and commercial customers." What is the basis for this statement?

Response:
See response to item 1.

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Item 3A

Last year (2000-2001) was an extremely volatile year. Rates in effect for the twelve month period ranged from around $4.28 to almost $10.00 (your schedule LB-1). The rates rose fairly rapidly in the fall and also dropped rapidly beginning in the spring. Please calculate what your Price per CCF would have been for last year assuming the Experimental Tariff was in place by October 1, 2000 for the following 12 months.

Response:

Based on using this year's risk premium, the fixed price for last year would have been 78 cents per ccf.

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Item 3B

In the above example, provide a comparison, using an average residential customer, of the actual costs last year to what they would have been under your proposal.

Response:

					Traditional PGA		
		Consumption Per Customer	Customer Charge	Base Rates	Approved PGA Rate	PGA Revenue	Total Bill
October	2000	25.71	$ 7.50	$ 5.36	$ 0.5334	$ 13.71	$ 26.57
November	2000	45.49	$ 7.50	11.35	0.6724	30.58	49.43
December	2000	134.89	$ 7.50	19.86	0.7633	102.96	130.32
January	2001	193.54	$ 7.50	30.12	0.7633	147.73	185.34
February	2001	140.38	$ 7.50	20.82	0.9942	139.57	167.88
March	2001	97.21	$ 7.50	13.26	0.7757	75.40	96.16
April	2001	82.95	$ 7.50	10.77	0.6640	55.08	73.35
May	2001	27.72	$ 7.50	5.66	0.6436	17.84	31.00
June	2001	17.10	$ 7.50	3.59	0.6189	10.58	21.67
July	2000	14.13	$ 7.50	2.97	0.5712	8.07	18.54
August	2000	11.93	$ 7.50	2.50	0.5712	6.81	16.82
Sept	2000	16.14	$ 7.50	3.39	0.5334	8.61	19.50
		807.18		$ 129.63		$ 616.96	$ 836.59

	Nov-April	May-Oct
First25 Ccf	$ 0.29	$ 0.21
next 25 CCf	0.20	0.15
Over 50 Ccv	0.175	0.045

					Fixed Rate PGA		
		Consumption Per Customer	Customer Charge	Base Rates	Fixed Rate as Calculated Sept 1, 2001	PGA Revenue	Total Bill
October	2000	25.71	$ 7.50	$ 5.36	0.6623	$ 17.03	$ 29.88
November	2000	45.49	$ 7.50	11.35	0.6623	30.13	48.97
December	2000	134.89	$ 7.50	19.86	0.6623	89.34	116.70
January	2001	193.54	$ 7.50	30.12	0.6623	128.18	165.80
February	2001	140.38	$ 7.50	20.82	0.6623	92.97	121.29
March	2001	97.21	$ 7.50	13.26	0.6623	64.38	85.14
April	2001	82.95	$ 7.50	10.77	0.6623	54.94	73.21
May	2001	27.72	$ 7.50	5.66	0.6623	18.36	31.52
June	2001	17.10	$ 7.50	3.59	0.6623	11.32	22.41
July	2000	14.13	$ 7.50	2.97	0.6623	9.36	19.83
August	2000	11.93	$ 7.50	2.50	0.6623	7.90	17.90
Sept	2000	16.14	$ 7.50	3.39	0.6623	10.69	21.58
		807.18		$ 129.63		$ 534.60	$ 754.23
Savings							$82.36

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Item 3C
Provide the same schedule for last year as you did in your example (BAT-2) for this proposed tariff.

Response:
See the attached schedule, BAT-2-2000.

1	Days of the Month	31	30	31	31	28	31
2	Normal	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02
3	Projected Wellhead Supply (Q)	312,291	664,863	1,211,371	1,446,410	876,973	760,573
4	Projected Storage Supply (S)	305,251	332,790	383,937	479,948	462,002	275,758
5	Total (Q+S)	617,542	997,653	1,595,308	1,926,358	1,338,975	1,036,331
6	Projected Sendout at City Gate	599,744	963,275	1,539,917	1,859,314	1,292,533	1,000,616
7	Projected Customer Usage						
8	Projected Residential Customer Usage	242,441	482,109	829,998	966,358	597,138	500,798
9	Projected Commercial Customer Usage	334,800	445,024	652,141	823,194	646,899	462,275
10	Total Projected Customer Usage (V)	577,242	927,133	1,482,139	1,789,553	1,244,037	963,073
11	Projected Wellhead Cost of Gas (O)	$ 5.324	$ 5.450	$ 5.565	$ 5.525	$ 5.260	$ 4.990
12	Projected Wellhead Cost (OxQ)	$ 1,662,638	$ 3,623,504	$ 6,741,281	$ 7,991,413	$ 4,612,880	$ 3,795,260
13	Projected Storage Cost (SI)	$ 9,643,372	$ 8,883,683	$ 7,637,413	$ 6,430,340	$ 4,921,412	$ 3,468,909
14	Projected Storage Volume (SQ)	3,067,292	2,762,041	2,429,251	2,045,315	1,565,366	1,103,365
15	Projected Injections Volume	-	-	-		-	-
16	Estimated Cost for Storage Injections	$ -	$ -	$ -	$ -	$ -	$ -
17	Weighted Average Cost of Gas (SI/SQ)	$ 3.144	$ 3.144	$ 3.144	$ 3.144	$ 3.144	$ 3.144
18	Storage Volumes Delivered (S)	305,251	332,790	383,937	479,948	462,002	275,758
19	Projected Volumes delivered by LNG***	21,700	21,000	21,700	21,700	61,757	21,700
20	Storage Delivered Cost ((SI/SQ)*S)	$ 959,689	$ 1,046,271	$ 1,207,073	$ 1,508,927	$ 1,452,504	$ 866,965
21	Demand Cost (D)****	$ 936,885	$ 936,885	$ 936,885	$ 936,885	$ 936,885	$ 936,885
22	Cost (OxQ)+(SI/SQ)*S)+D	$ 3,559,212	$ 5,606,660	$ 8,885,239	$ 10,437,226	$ 7,002,269	$ 5,599,111
23	Sales Volumes (V)	577,242	927,133	1,482,139	1,789,553	1,244,037	963,073
24	Fixed Cost excluding Transportation & Risk Premium Per DT	$ 6.17	$ 6.05	$ 5.99	$ 5.83	$ 5.63	$ 5.81
25	Pipeline Transportation Per DT						
26	Risk Premium per DT						
27	Total Fixed Price Per Therm						
28	Total Fixed Price CCF						

*** LNG volumes are included on line 18 (Storage Delivered Volumes (S))

**** Demand cost of residential and commercial customers

No								
1	Days of the Month	30	31	30	31	31	30	Yearly Vol
2	Normal	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	DT
3	Wellhead Supply (Q)	383,299	245,634	237,710	245,634	245,634	237,710	6,868,107
4	Storage Supply (S)	183,191	32,958	21,000	21,700	21,700	32,488	2,552,726
5	Total (Q+S)	566,490	278,592	258,710	267,334	267,334	270,199	9,420,833
6	Projected Sendout at City Gate	550,196	270,919	251,610	259,997	259,997	262,755	**9,110,879**
7	Projected Customer Usage							
8	Projected Residential Customer Usage	**264,776**	**104,302**	**87,181**	**95,092**	**77,575**	**85,985**	**4,333,761**
9	Projected Commercial Customer Usage	**264,776**	**156,452**	**154,989**	**155,150**	**172,667**	**166,912**	**4,435,289**
10	Total Projected Customer Usage (V)	529,553	260,754	242,170	250,242	250,242	252,896	8,769,050
11	Wellhead Cost of Gas (O)	$ 4.720	$ 4.630	$ 4.605	$ 4.590	$ 4.567	$ 4.567	
12	Wellhead Cost (OxQ)	**$ 1,809,172**	**$ 1,137,286**	**$ 1,094,656**	**$ 1,127,460**	**$ 1,126,724**	**$ 1,085,623**	**$ 35,807,911**
13	Projected Storage Cost (SI)	$ 2,601,943	$ 4,386,004	$ 6,574,690	$ 8,791,511	$ 10,995,251	$ 13,195,867	
14	Projected Storage Volume (SQ)	827,607	1,144,416	1,611,458	2,090,458	2,568,758	3,047,058	
15	Projected Injections Volume	500,000	500,000	500,000	500,000	500,000	500,000	3,000,015
16	Estimated Cost for Storage Injections	$ 2,360,000	$ 2,315,000	$ 2,302,500	$ 2,295,000	$ 2,293,500	$ 2,283,500	
17	Weighted Average Cost of Gas (SI/SQ)	$ 3.144	$ 3.833	$ 4.080	$ 4.206	$ 4.280	$ 4.331	
18	Storage Volumes Delivered (S)	183,191	32,958	21,000	21,700	21,700	32,488	2,552,740
19	Volumes delivered by LNG***	21,000	21,700	21,000	21,700	21,700	21,000	297,676
20	Storage Delivered Cost ((SI/SQ)*S)	**$ 575,940**	**$ 126,313**	**$ 85,679**	**$ 91,260**	**$ 92,884**	**$ 140,696**	**$ 8,154,221**
21	Demand Cost (D)****	**$ 936,885**	**$ 936,885**	**$ 936,885**	**$ 936,885**	**$ 936,885**	**$ 936,885**	**$ 11,242,645**
22	Cost (OxQ)+(SI/SQ)*S)+D	$ 3,321,997	$ 2,200,485	$ 2,117,221	$ 2,155,606	$ 2,156,493	$ 2,163,205	$ 55,204,747
23	Sales Volumes (V)	529,553	260,754	242,170	250,242	250,242	252,896	8,769,056
24	Fixed Cost excluding Transportation & Risk Premium Per DT	**$ 6.27**	**$ 8.44**	**$ 8.74**	**$ 8.61**	**$ 8.62**	**$ 8.55**	**$ 6.295**
25	Pipeline Transportation Per DT							**$ 0.06**
26	Risk Premium per DT						*****	**$ 1.24**
27	Total Fixed Price Per Therm							**$ 0.7597**
28	Total Fixed Price CCF							**$ 0.7825**

*** LNG volumes are included on line 18 (Storage Delivered Volumes (S))

**** Demand cost of residential and commercial customers

***** Note: This Risk Premium was based on 2001 and not on 2000, and may not be applicable to this time period

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Item 4

You have provided two affidavits of customers testifying to the need for a fixed price gas cost, thus avoiding volatility. Both of these are commercial customers. Have you done any studies or surveys to determine the opinions or desires of your residential customers in regards to paying a risk premium to avoid volatility?

Response:

The company has not conducted any formal studies of residential customers regarding price volatility. However, it is our belief based on informal studies that both residential and Commercial customers desire a stable pricing mechanism.

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Item 5

Provide a worst case and best case scenario, using the example in 4B, if the weather is 20% colder than normal and 20% warmer than normal. Include in each of the two examples, a situation in which the gas is $2.00 cheaper than what is shown in BAT-2 and also $4.00 more expensive. Determine the effect on the Company and the customers.

Response:

As requested, We are estimating the cost that could be observed under a cold case. An incremental $ 4.00 price increase was suggested per TRA, but since last year's weather was normal, and we experienced $ 10 gas in January, the incremental gas cost being used has been assumed to be $ 6.00 in the cold case. The customer and company affects have been listed below with assumptions. However, these scenarios assume that all costs are known, quantifiable and weighted accurately. **The Company does not believe that the inherent risks of the Fixed Rate PGA can be fully quantified with this type of analysis.**

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Colder Case Estimate

Customer

The customer will not be affected by colder weather or price increases. His or her volumes of gas may increase but his price will not.

Company

The Company could experience the following effects, which may not include all of the possible risks:

Total Risk Premium In a cold case, the estimated volume that would be billed to customers would be 10.63 million dkt. Based on the $ 1.24 Dkt risk premium, the company would generate $13.2 million dollars.

Additional Revenues Since the normal case accounts for all demand charges, any additional volumes in the cold case will result in additional revenues. The unit price of demand charges is about $ 1.28 per Dkt. With an incremental volume of 1.934 million Dkt. This revenue would be $ 2.5 million dollars.

Revenue due to Risk Premium and additional revenue The total for these two items is $ 15.7 million.

Incremental Price Effect In the cold case, an additional 1.934 million Dkt of gas will have to be purchased at an assumed rate of $ 6.00, resulting in $11.6 million dollars of additional cost.

Unbilled effect. In October, the unbilled gas cost will be estimated and the volumes that are billed will be split between Sequent and the regulated PGA. This activity could result in an estimated loss of 130,000 Dkt at a cost of $2.39 per Dkt, or approximately $0.310 million dollars.

Unaccounted & Loss and Reduced customer effect. If the unaccounted-for factor increases by 2% and the customer count decreases by 2%, it will result in approximately 426,000 Dkt in additional gas costs that will not be recovered, or approximately $2.2 million dollars.

Interruptible Risk Effect. Interruptible customer swings could possibly result in the withdrawal and replacement of 1 million Dkt of gas from storage. This activity would force the company to inject gas into storage at the flowing rate and withdraw gas from storage at weighted average cost of gas, which would be approximately $1.8 million dollars.

Capacity Rate Change Effect. Assuming Southern Natural were to have a 10% change in rates would result in an additional gas cost of approximately $0.38 million dollars.

Overall Cost Effect. The overall effect from all of these assumptions would be an additional gas cost of approximately $16.29 million dollars.

Overall Net Effect The overall net effect would be $15.65 million dollars minus $16.29 million dollars which results in a risk premium of $-0.64 million dollars.

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Normal Case Scenario

Customers

In a normal case, the customers will use their normal volume, and their unit price will be fixed.

Company

The Company could experience the following effects, which may not include all of the possible risks:

Total Risk Premium In a normal case, the estimated volume that would be billed to customers would be 8.77 million. Based on the $1.24 Dkt risk premium, the company would generate $10.9 million dollars.

Unbilled effect. In October, the unbilled will be estimated and the volumes that are billed will be split between Sequent and the regulated PGA. This activity could result in an estimated loss of 130,000 Dkt at a cost of $2.39 per Dkt or approximately $0.310 million dollars.

Unaccounted & Loss and Reduced Customer Effect. If the lost and unaccounted-for gas factor increases by 2% and the number of customers decreases by 2%, it will result in approximately 350,000 Dkt in gas cost that will not be recovered, or approximately $1.8 million dollars.

Interruptible Risk Effect. Interruptible customer swings could possibly result in the withdrawal and replacement of 1 million Dkt of gas from storage. This activity would force the company to inject gas into storage at flowing rate and withdraw gas from storage at the weighted average cost of gas, which would be approximately $1.8 million dollars.

Capacity Rate Change Effect. Assuming Southern Natural were to have a 10% change in rates would result in an additional gas cost of approximately $0.38 million

Overall Cost Effect. The overall cost effect from all of these assumptions would be a cost of approximately $4.3 million.

Overall Net Effect – The net effect of the revenue minus the overall cost effect would result in a risk premium of $6.6 million.

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Warm Case Scenario

Customers

In a warm case, the customers will use about 21% less gas, and their unit price will not change.

Company

The Company could experience the following effects, which may not include all of the possible risks:

Total Risk Premium In a warm case, the estimated volume that would be billed to customers would be 6.9 million. Based on the $1.24 Dkt risk premium, the company would generate $8.5 million dollars.

Incremental Savings In the normal case, storage volumes are consumed, but since the warm case only uses 6.9 million Dkt, most of the storage volumes will not be used , which results in an incremental reduction in cost of $2.4 million dollars.

Revenue due to Risk Premium and the incremental savings The total for these two items is $10.9 million.

Reduced Volume Effect. The warmer weather could result in the Company not collecting its demand cost on 1.86 million Dkt or approximately $2.3 million.

Unbilled effect. In October, the unbilled will be estimated and the volumes that are billed will be split between Sequent and the regulated PGA. This activity could result in an estimated loss of 130,000 Dkt at a cost of $2.39 per Dkt or approximately $0.310 million dollars.

Unaccounted & Loss and Reduced Customer Effect. If the lost and unaccounted-for gas factor increases by 2% and the number of customers decreases by 2%, it will result in approximately 272,000 Dkt in gas cost that will not be recovered, or approximately $1.4 million dollars.

Interruptible Risk Effect. Interruptible customer swings could possibly result in the withdrawal and replacement of 1 million Dkt of gas from storage. This activity would force the company to inject gas into storage at flowing rate and withdraw gas from storage at the weighted average cost of gas, which would be approximately $1.8 million dollars.

Capacity Rate Change Effect. Assuming Southern Natural were to have a 10% change in rates would result in an additional gas cost of approximately $0.38 million

Overall Cost Effect. The overall cost effect from all of these assumptions would be a cost of approximately $6.2 million.

Overall Net Effect – The net effect of the revenue incremental savings minus the overall cost effect would result in a risk premium of $ 4.7 million.

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Item 6
A risk premium of $1.24 appears high at today's gas of $3.10 to $3.20 for January gas on the NYMEX. This, incidentally, is roughly 19% of the total price of the Fixed Rate Charge and it also represents 40% of the current cost of gas. Address the issue that, while this fixed-rate charge represents stable gas bills for the customers it also represents **no** reduced rates for the customers when the price of gas spikes downward.

Response:
The Company incurs more cost than $3.10 for gas. We have substantial fixed cost and storage volumes that are injected at rates from prior periods, which can be less or more than this $3.10 price. The $3.10 NYMEX is a price at a specific time. If this contract is prudent on a day when it is trading at $3.10, we will receive a specific volume for that price in January. The $3.10 price does not cover the ability to take as little or much as needed or the risk associated with fixed cost. The $1.24 risk premium is an insurance policy that covers Chattanooga gas customers through a warm winter or cold winter. The Company has offered this plan to address the customers' and Authority's concern around price volatility rather than the possibility of reduced rates.

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Item 7
What percentage of the projected gas used next year will be from storage? What is the average cost of gas in storage? Quantify the impact on your fixed rate factor.

Response:
The amount of storage supply projected to be used for next year is listed on Row 4 of the Exhibit BAT-2. The projected weighted cost of storage for these volumes can be found on row 17.

The storage cost contributes about 5.6 cents per Ccf to the overall rate, which is about 8% of the total rate.

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Item 8
Exhibit Bat-2 shows 9,110,879 DTs at City Gate send-out and projected customer usage of 8,769,050. Does this represent a projected loss and unaccounted for of 3.8%. How does this compare to the last 5 years?

Response:
The 3.75% is the projected loss and unaccounted for factor that was used in Exhibit BAT-2. This factor was developed from a comparison of gas purchased on behalf of Chattanooga gas and the volumes that were delivered and billed to customers. The estimated loss and unaccounted for volume was 476,684 dekathems for the period of August 2000 to July 2001. The 3.75% number was developed by dividing this unaccounted for number by all volumes delivered to the city gate from Sequent Energy Management or though the LNG system. This denominator does not include transport volumes of 6.4 million dekatherms which produces an unaccounted for factor of 2.49%. The average lost and unaccounted-for factor from 1996 – 2000 is 2.06%.

Since interruptible customers transport their own commodity volumes, they are not billed for loss and unaccounted for gas.

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Item 9
How are projected gas volumes determined?

Response:
Projected volumes were determined through normalizing city gate data from the 2000/2001 year. This data was normalized for weather. A probability of weather was developed over a 32 year period. Weather with a probability of 50% was used to determine the projected volume of gas that would be consumed at the city gate. This number was then used to determine the amount of gas required at the wellhead and the amount that would be accounted for on customers' meters.

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Item 10
Projected FERC transportation rates are included in this formula. What happens if new FERC rates are approved during the period? What about refunds that may be received during the period? How are the refunds to be accounted for and who gets the refund?

Response:
If the FERC approves increases in the transportation rates after the Fixed Rate PGA is established, the added cost related to providing service to the residential and commercial customers will be absorbed by AGL Resources stockholders. The impact of such a rate change attributed to the provision of service to other customers will flow through the PGA applicable to those customers.

Any refunds attributable to the residential and commercial classes for periods prior to the effective date of the Fixed Rate PGA will be deferred and refunded in a manner acceptable to the TRA. Refunds attributable to customers not covered by the fixed rate PGA will continue to treated in accordance with the PGA rule. Refunds attributable the residential and commercial customers for periods beginning after the effective date of the Fixed Rate PGA would be retained by the Company.

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Item 11
Provide the percentage of LNG cost in the Georgia Marketers prices verses the percentage of LNG costs calculated in the Chattanooga Fixed Rate. Also what is the traditional percentage of LNG cost verses total gas cost in Georgia versus Tennessee?

Response:
Information concerning the Georgia Marketer's LNG cost is not available to Chattanooga Gas Company, Sequent, or other AGL Resources' Companies.

The percent of LNG assets that AGLC manages is available and that amount is about 7.1 million dekatherms and represents about 12% of AGLC's total storage volumes.

In Chattanooga, CGC has LNG storage capability of 1.2 million dekatherms, which represents about 25% of CGC's total storage volumes.