CASE NUMBER:

99-176

DELTA NATURAL GAS COMPANY, INC.
Rates - General
HISTORICAL TEST PERIOD

IN THE MATTER OF AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.

SEQ NBR	ENTRY DATE	REMARKS
0001	04/29/1999	Notice of Intent.
0002	04/30/1999	Acknowledgement letter of Notice of Intent.
0003	07/02/1999	Application.
M0001	07/02/1999	ORDA LEDFORD CITIZEN-LETTER OF CONCERN TO INCREASE
0004	07/06/1999	Acknowledgement letter.
M0002	07/07/1999	DELTA NATURAL GAS-MOTION TO CONSOLIDATE & MAINTAIN PROCEDURAL SCHEDULE
0006	07/08/1999	Response sent to Odra Ledford protest letter.
0005	07/09/1999	No deficiency letter.
M0003	07/09/1999	E BLACKFORD AG-MOTION TO INTERVENE
0007	07/13/1999	Order granting motion of the Attorney General for full intervention.
M0005	07/13/1999	ROBERT WATT DELTA NATURAL GAS-REPLY IN SUPPORT OF MOTION TO CONSOLIDATE & MAINTAIN PROCEDUR
0008	07/15/1999	Data Request Order; response due 7/29
M0006	07/26/1999	CRACRAFT,RITCHIE CITIZENS-LETTER OF CONCERN TO RATE INCREASE
0009	07/28/1999	Response sent to Frank and Dolly Cracraft letter of concern to rates.
0010	07/28/1999	Response sent to C.B. Ritchie letter of concern to rates.
M0007	07/28/1999	ROBERT WATT DELTA NATURAL GAS-RESPONSE TO PSC DATA REQ FOR INFO DATED JULY 15,99
0011	07/30/1999	Order setting forth the procedural schedule to be followed in this case.
0012	08/05/1999	Order denying motion to consolidate; Case No. 99-046 is dismissed.
0013	08/11/1999	Data Request Order, response due 8/23/99.
M0008	08/11/1999	BERNICE CHEEKS CITIZEN-LETTER OF CONCERN TO RATES
M0009	08/11/1999	AG E BLACKFORD-INITIAL REQUEST FOR INFORMATION BY THE AG
M0010	08/13/1999	E BLACK FORD AG-NOTICE OF CORRCTIN IN THE INITIAL REQ FOR INFO BY THE AG
M0011	08/18/1999	ROBERT WATT DELTA NATURAL GAS-NOTICE OF FILING PROOF OF PUBLICATION
M0012	08/23/1999	ROBERT WATT DELTA NATURAL GAS CO-RESPONSE TO DATA REQUEST OF THE PSC & AG DATED AUG 11,99
0014	08/30/1999	Interest & Concern resp. to Bernice Cheeks; req. to intervene may be filed.
0016	09/01/1999	Letter advising that a disk is missing from Delta's response filed on 8/23/99.
0015	09/02/1999	Data Request Order, response due 9/13/99.
M0013	09/02/1999	RANDALL WALKER DELTA NATURAL GAS-DISKETTE TO QUESTION 6 TO RESPONSE TO ORDER OF AUGUST 11,9
M0014	09/03/1999	E BLACKFORD AG-SUPPLEMENTAL REQUEST FOR INFORMATION
M0015	09/07/1999	JOHN HALL DELTA NATURAL GAS-MONTHLY UPDATE TO QUESTION NO 48
M0016	09/13/1999	ROBERT WATT DELTA NATURAL GAS-RESPONSE TO SUPPLEMENTAL DATA REQ OF THE PSC & AG DATED SEPT
0017	09/14/1999	Data Request Order, response due 9/24/99.
M0019	09/23/1999	E BLACKFORD AG-PREFILED TESTIMONY HENKES,GALLIGAN,ESTOMIN,WEAVER
M0017	09/24/1999	J. MEL CAMENISCH DELTA NATURAL GAS-RESPONSE TO DATA REQUESTS DATED 9/14/99 & MOTION OF CONF
M0018	09/28/1999	E BLACKFORD AG-CERTIFICATE OF SERVICE & OF FILING
0018	10/04/1999	Data Request Order, response due 10/14/99 from the Attorney General.
M0020	10/04/1999	ROBERT WATT DELTA NATURAL GAS-DATA REQ TO AG
M0021	10/06/1999	JOHN HALL DELTA NATURAL GAS CO-MONTHLY UPDATE TO QUESTION NO 48 OF DATA REQ FILED JULY 15,9
M0022	10/14/1999	AG E BLACKFORD-AG RESPONSES TO DATA REQ PROPOUNDED BY DELTA NATURAL GAS CO
M0023	10/14/1999	E BLACKFORD AG-MOTION FOR ENLARGEMENT OF TIME
M0024	10/14/1999	AG E BLACKFORD-AG RESPONSE TO PSC ORDER OF OCT 4,99
0019	10/18/1999	Letter granting petition for confidentiality filed 9/24/99 by Delta.
M0026	10/25/1999	ROBERT WATT DELTA NATURAL GAS-TESTIMONY OF SEELYE,BLAKE,BROWN
M0025	10/27/1999	E BLACKFORD AG-NOTICE THAT ATTACHMENTS RESPONSIVE TO DATA REQ 26 ARE NOT INCLUDED AS
0020	10/28/1999	Order granting the AG an additional day to respond to Delta's info requests.
M0027	10/28/1999	DELTA NATURAL GASROBERT WATT-MOTION TO STRIKE TESTIMONY OF AG WITNESSES
M0028	10/28/1999	AG E BLACKFORD-MOTION TO STRIKE & BAR FROM CONSIDERATION CERTAIN TESTIMONY
M0029	10/29/1999	AG E BLACKFORD-RESPONSE TO DELTA MOTION TO STRIKE TESTIMONY OF AG WITNESSES
M0030	10/29/1999	DELTA ROBERT WATT-RESPONSE TO AG MOTION TO STRIKE

DELTA NATURAL GAS COMPANY, INC.
Rates - General
HISTORICAL TEST PERIOD

IN THE MATTER OF AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.

SEQ NBR	ENTRY DATE	REMARKS
0021	11/03/1999	Letter containing PSC Staff questions; answers due no later than 11/17/99.
M0031	11/04/1999	E BLACKFOR AG-NOTICE OF FILING & CERTIFICATE OF SERVICE
M0032	11/09/1999	VIVIAN LEWIS/COURT REPORTER-HEARING EXHIBITS HELD 10/28/99
M0033	11/09/1999	VIVIAN LEWIS/COURT REPORTER-TRANSCRIPT FOR HEARING HELD 10/28/99 VOL. I OF II
M0034	11/12/1999	JOHN HALL DELTA NATURAL GAS-RESPONSE TO STAFF REQUEST MADE DURING HEARING HELD ON OCT 28,29
M0035	11/12/1999	VIVIAN LEWIS/COURT REPORTER-TRANSCRIPT FOR HEARING HELD 10/29/99
M0036	11/17/1999	E BLACKFORD AG-RESPONSE TO POSTHEARING DATA REQ BY KY PSC ON NOV 3,99
M0037	11/17/1999	JOHN HALL DELTA NATURAL GAS-RESPONSE TO POST HEARING STAFF REQ MADE TO STEVE SEELYE
M0038	11/29/1999	ROBERT WATT DELTA NATURAL GAS-BRIEF
M0039	11/29/1999	AG-POSTHEARING BRIEF
0022	11/30/1999	Order denying Delta's Motion to Strike the Testimony of the AG's Witnesses.
0023	12/27/1999	Final Order approving rates in Appendix B and approving proposed WNA.
M0040	01/06/2000	CONNIE KING DELTA NATURAL GAS-REVISED TARIFF SHEETS
M0041	01/10/2000	CONNIE KING DELTRAN INC-RESPONSE TO ORDER OF DEC 27,99
M0042	01/18/2000	AG E BLACKFORD-MOTION FOR REHEARING
M0043	02/01/2000	ROBERT WATT DELTA NATURAL GAS-RESPONSE TO AG MOTION FOR REHEARING
0024	02/07/2000	Order on Rehearing
M0044	06/27/2000	CONNIE KING/DELTA NATURAL GAS-RESPONSE TO 12/27/99 ORDER
M0045	05/15/2001	CONNIE KING DELTA NATURAL GAS-ANNUAL REPORT ON WEATHER NORMALIZATION ADJUSTMENT

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797

PHONE: 859-744-6171
FAX: 859-744-3623

DGAS
NASDAQ
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May 14, 2001

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MAY 15 2001

PUBLIC SERVICE
COMMISSION

Mr. Thomas Dorman
Executive Director
Public Service Commission
P O Box 615
Frankfort, KY 40602

RE: CASE NO. 99-176

Dear Mr. Dorman:

Per the Commission's Order in Case No. 99-176 dated December 27, 1999 attached is Delta's annual report on its Weather Normalization Adjustment (WNA) program. Delta's proposed WNA was approved for gas service provided for January – April 2000, December 2000 – April 2001 and December 2001 – April 2002.

The attached report includes the financial and statistical data requested in Appendix C of the Commission's Order for the heating season of December 1, 2000 – April 30, 2001.

If you have any questions regarding this report, please contact me at 859-744-6171 extension 140.

Please acknowledge receipt of this filing by stamping the extra copy of the cover letter and returning to me in the envelope provided.

Sincerely,

Connie King

Connie King
Director – Rates & Treasury

Delta Natural Gas Company, Inc.

Weather Normalization Annual Report

Fiscal 2001

Summary

	December	January	February	March	April	Total
WNA Customers						
Residential	34,456	34,857	34,907	34,856	34,696	173,772
Small Non-Residential	4,618	4,709	4,718	4,713	4,711	23,469
Total	**39,074**	**39,566**	**39,625**	**39,569**	**39,407**	**197,241**
WNA Revenue (Expense)						
Residential	$ (285,784.55)	$ (541,143.66)	$ 130,587.89	$ 56,097.44	$ (105,533.21)	$ (745,776.09)
Small Non-Residential	$ (79,372.81)	$ (159,764.97)	$ 41,619.45	$ 12,155.27	$ (23,703.55)	$ (209,066.61)
Total	**$ (365,157.36)**	**$ (700,908.63)**	**$ 172,207.34**	**$ 68,252.71**	**$ (129,236.76)**	**$ (954,842.70)**
MCF Volume Adjustment						
Residential	(78,894)	(149,388)	36,050	15,486	(29,134)	(205,879)
Small Non-Residential	(25,924)	(55,576)	14,103	3,773	(7,409)	(71,032)
Total	**(104,818)**	**(204,964)**	**50,153**	**19,259**	**(36,542)**	**(276,911)**
WNA Revenue per Customer						
Residential	$ (8.29)	$ (15.52)	$ 3.74	$ 1.61	$ (3.04)	$ (21.51)
Small Non-Residential	$ (17.19)	$ (33.93)	$ 8.82	$ 2.58	$ (5.03)	$ (44.75)
Heating Degree Days						
Billed Actual	829	1,267	1,034	721	533	4,384
Billed Normal	638	944	1,122	726	482	3,912
% of Normal	129.94%	134.22%	92.16%	99.31%	110.58%	112.07%
Customer Contacts						
Inquiries	-	-	5	4	-	9
Complaints	-	1	-	-	-	1

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
NOV - 4 1999
PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF	**)**	
DELTA NATURAL GAS COMPANY, INC.	**)**	**CASE NO. 99-176**

RESPONSES TO STAFF DATA REQUESTS
MADE ON OCTOBER 29, 1999

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that this the 4th day of November, 1999, I have filed the Original and eight copies of the attached Response to Staff Data Requests made during the hearing held in the above styled action on October 28-29, 1999, with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and that I have served the parties by mailing a true copy of same, postage prepaid to the following:

JOHN F HALL
VICE PRESIDENT-FINANCE SEC TREAS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

HONORABLE ROBERT M WATT III
STOLL KEENON & PARK LLP
201 EAST MAIN STREET SUITE 1000
LEXINGTON KY 40507 1380

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-176
Response of Robert J. Henkes
Staff Hearing Data Request

1. Please reconcile Schedules RJH-3 and RJH-5.

Answer:

Schedule RJH-5 did not reconcile to the amount of ($666,905) shown on Summary Schedule RJH-3 because the reduction adjustments on Schedule RJH-5 lines 7 and 10 were not made on Mr. Henkes's computer model. Attached is a copy of Schedule RJH-5, with the addition of lines 7 and 10 which are highlighted, and Schedule RJH-3. These changes have no impact on revenue requirement.

Sch. RJH-5

DELTA NATURAL GAS COMPANY
ACCUMULATED DEFERRED INCOME TAXES

ADIT Balances as of 12/31/98:	Delta (Per Books) (1)		Adjustment	AG (PSC-Authorized in Case 97-066) (2)	
1. A/C 28201 - Accel. Depreciation	($10,034,325)			($10,034,325)	
2. A/C 28202 - Pension Plan	(567,200)	*	567,200		
3. A/C 28203 - Stock Plan	22,600	*	(22,600)		
4. A/C 28205 - Alt. Minimum Tax	1,274,100			1,274,100	
5. A/C 28206 - Annual Leave	153,500	*	(153,500)		
6. A/C 28207 - Adv. for Construction	43,700			43,700	
7. A/C 28208 - Ferrin Note Amort.	16,200	**	(16,200)		
8. A/C 28209 - Unbilled Revenues	670,100	*	(670,100)		
9. A/C 282010 - Unamort. Debt Exp.	(455,800)		67,595	(388,205)	(3)
10. A/C 282011 - Bad Debt Reserve	47,300	*	(47,300)		
11. A/C 282012 - Storage Gas	1,100			1,100	
12. A/C 28301 - Regulatory Income Tax	(500)	*	500		
13. A/C 28302 - Regulatory ITC	392,500	***	(392,500)		
14. TOTAL ADIT	($8,436,725)		($666,905)	($9,103,630)	

* There are no rate base components associated with these deferred taxes

** Associated with Canada Mountain

*** There are no rate base components associated with these deferred taxes. In addition, these Regulatory ITC deferred taxes are exactly offset by the corresponding Regulatory ITC liability of $392,500 in Account 254 (See response to PSC-18).

(1) FR #6-r balance sheet as of 12/31/98 and response to PSC data request 1-12, page 3 of 5
(2) Response to AG-19 b

(3) Unadjusted per books balance at 12/31/98:	($455,800)
Percentage allocated to Delta (remove CM portion):	85.17%
ADIT associated with Delta, excusive of CM	($388,205)

Sch. RJH-3

DELTA NATURAL GAS COMPANY
SUMMARY OF RATE BASE POSITIONS

	Delta (1)	Adjustment	AG	
1. Plant In Service	$114,965,626		$114,965,626	
2. Depreciation Reserve	(35,230,946)		(35,230,946)	
3. Net Plant in Service	79,734,680		79,734,680	
4. Cash Working Capital	1,097,255	(47,000)	1,050,255	Sch. RJH-4
5. Prepayments	106,884	100,451	207,335	(2)
6. Materials and Supplies	451,812	121,751	573,563	(2)
7. Gas in Storage	265,579		265,579	
8. Acc. Def. Income Taxes	(8,436,725)	(666,905)	(9,103,630)	Sch. RJH-5
9. Unamortized Debt Expense	3,108,925		3,108,925	
10. Advances For Construction	(220,060)		(220,060)	
11. Depreciation Adjustment	(20,212)		(20,212)	
12. Customer Deposits	—	(594,863)	(594,863)	Sch. RJH-6
TOTAL NET RATE BASE	$76,088,138	($1,086,566)	$75,001,572	

(1) FR #6-h, Schedule 7
(2) 13-month average test year balance, per response to PSC-26 b

Commonwealth of Kentucky
Before the Public Service Commission
Case No. 99-176
Response of Carl G. K. Weaver
Staff Hearing Data request

2. What would be the cost of equity if the Commission was to use an imputed capital structure that contained 40% equity capital?

Answer:

To determine the cost of equity if the capital structure were to contain 40% equity capital, the effect of the additional equity on the risk of Delta versus the risk of the similar companies must first be examined. The effect on capitalization, repayment obligations, cash flow interest coverages, and other risk measures must be determined so that these values can be compared to the five companies that were selected as being as similar as possible to Delta.

Delta's total capitalization on December 31, 1998, as adjusted and presented by the Company, is assumed to be $76,728,462 (Case No. 99-176, Weaver, Testimony, Sch. 35). At 40%, equity capital would be $30,691,385 which is $7,823,859 more equity than the $22,867,526 amount contained in the adjusted capitalization. If we assume that long-term debt and short-term debt are reduced by the proportional amounts then:

Capital	12/31/98 Adjusted Amount *	Percentage	Debt Amount Reduction
Long-term Debt	$46,169,905	85.7%	$6,706,657
Short-term Debt	7,691,031	14.3	1,117,202
	$53,860,936	100.0%	$7,823,859

* Case No. 99-176, Sch. - Note: All Schedule references are to Weaver, Testimony

Equity to Total Capitalization Ratio (Case No. 99-176, Sch. 35)

Increasing the amount of equity in the capital structure to 40% results in a December 31, 1998 capital structure, as presented by Delta, as follows:

Capital	12/31/98 Adjusted Amount *	Amount Changed	Adjusted Amount @ 40% Equity	Imputed Capital Structure
Long-term Debt	$46,169,905	($6,706,657)	$39,463,248	51.4%
Short-term Debt	7,691,031	(1,117,202)	6,573,829	8.6%
Common Equity	22,867,526	7,823,859	30,691,385	40.0%
Total	$76,728,462	0	$76,728,462	100.0%

* Case No. 99-176, Sch. 35

The change in the -
Total Liabilities to Total Assets Ratio (Case No 99-046, Sch. 5):

Delta's 1998 fiscal year-end total assets were $102,867 thousand (Case No. 99-046, Sch. 5). Fiscal year end equity was $29,810 thousand (Case No. 99-046, Sch. 6). Increasing the equity by $7,824 thousand would result in an equity amount of $37,634 thousand and equity to total assets would become 36.6%. Subtracting the 36.6% equity to total asset ratio from 1.00 would result in a total liabilities to total assets ratio of 63.4% as compared to 66% for the five companies.

Conclusion: Delta, having a smaller amount of repayment obligations, would have somewhat less risk than the five companies.

The change in the -
Selected Companies Capital Structure Comparison (Case No. 99-046, Sch. 7):

The comparison of the fiscal year-end capital structure shown in Schedule 7 (Case No. 99-046) would be:

	Short-term Debt	Long-term Debt	Preferred Stock	Common Equity	Total
5-Co. Average	9.1%	47.2%	1.9%	41.8%	100%
Delta	2.2%	57.8%	-	40.0%	100%

Conclusion: Delta's risk is close to the risk of the five companies. It has a small amount more risk.

The change in the -
Cash Flow Coverage of Interest (Case No. 99-046, Sch. 13 & Sch. 14):

The embedded cost of long-term debt was 7.48% and the embedded cost of short-term debt was 5.41%. This results in an interest reduction on long-term debt in the amount of $501,658 and an interest reduction on short-term debt in the amount of $60,441. The total interest reduction would be $562,099.

	1997	1998	Average
Cash Flow from Operating Activities	$6,209	$8,922	$7,566
Adjusted Interest:			
Actual Amount	3,632	4,438	
Reduction	562	562	
Hypothetical Interest Amount	3,070	3,876	
Coverage	3.02 times	3.30 times	3.16 times

Note: Cash flow time interest coverage is calculated as cash flow from operating activities plus interest and that total quantity is divided by interest. The amounts are taken from the company's cash flow statements. There is no short-term debt in cash flow from operating activities.

Average for the five selected companies	- 3.18 times	(Case No. 99-046, Sch. 14)
Hypothetical Average for Delta	- 3.16 times	

Conclusion: Delta and the five companies would have an equal amount of risk with respect to cash flow interest coverage.

Change in -
Other Selection Criteria

The change in the amount of equity in the capital structure would not effect the amount of Delta's Total assets, its growth in total assets, or its net sales to total assets. These risk measures would not change.

Change in -
Published Risk Measures:

The effect of changing the capital structure on Standard & Poor's and Value Line's risk measures was examined an it does not appear that these measures would be effected by increasing the capital structure to 40% equity.

Conclusion: The cost of equity for Delta would be the same as the cost of equity for the five companies that were selected as being as similar as possible.

Delta's cost of equity without weather normalization would be in the range from 9.75% to 10.75%.

If Delta is allowed a weather normalization clause, its total risk would be less than the risk of the five companies. Delta's cost of equity would be in a range from 9.50% to 10.50%.

COMMONWEALTH OF KENTUCKY
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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

November 3, 1999

Elizabeth Blackford, Esq.
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, Kentucky 40602-8204

Robert M. Watt III, Esq.
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, Kentucky 40507-1380

Re: Case No. 99-176
Delta Natural Gas Company

Dear General Blackford and Mr. Watt:

Pursuant to our agreement, enclosed are Commission Staff's written questions for Messers. Seelye and Estomin. Their written answers to these questions should be filed with the Public Service Commission no later than November 17, 1999.

Sincerely,

Gerald E. Wuetcher
Staff Attorney

Enclosure
cc: Case File No. 99-176

QUESTIONS FOR WILLIAM STEVEN SEELYE

1. Using Mr. Seelye's data and the minimum intercept model, Commission Staff obtained the following results:

$$Y = 1.81 + 0.77X \text{ (no weighting)}^1,$$

where Y = Unit cost (\$/foot)

X = diameter of pipe (inches).

When Commission Staff used the square root of Q as the weight, it obtained following results:

$$\sqrt{Q_i}\,Y_i = 389.3 + 1.089(\sqrt{Q_i}\,X_i)$$

$$\sqrt{Q_i}\,Y_i = -0.15885\sqrt{Q_i} + 1.296(\sqrt{Q_i}\,X_i)$$

In his direct testimony, Mr. Seelye obtained the predicted equation of $Y = 3.14 + 0.86X$ that results in a customer related allocation of 58 percent. See Testimony of William Steven Seelye, Exhibit 4-3. In his rebuttal testimony, Mr. Seelye obtained the equation of $Y = 2.92 + 0.802X$. See Rebuttal Testimony of William Steven Seelye at 12.

a. Describe in detail how the results in Exhibit 4-3 were obtained. Show each step of the calculations and state all assumptions used.

b. Describe all transformations (e.g., scaling of data or conversions from feet to inches and vice versa) performed to obtain the results in Exhibit 4-3.

c. What observations, if any, were deleted? Why?

d. State which of the following was estimated:

---

[1] This result yields a Minimum intercept cost of \$11,726,829.

(1) $\Sigma w_i(Y_i - (\alpha + \beta^* X_i))$. (<u>See</u> Testimony of William Steven Seelye at 13.)

(2) $\Sigma w_i(Y - (\alpha + \beta X_i))^2$. (<u>See</u> Rebuttal Testimony of William Steven Seelye at 11.)

e. According to Kmenta[2], a weighted least squares equation such as $\Sigma w_i Y_i = \alpha \Sigma w_i + \beta^* X_i \Sigma w_i$ "can only be estimated if Σw_i is known <u>and the intercept of the regression equation is zero</u>." Given this proposition, how was each intercept (3.14 and 2.92) obtained?

2. In his rebuttal testimony, Mr. Seelye indicates that the estimated equation is now given by $Y = 2.92 + 0.802X_i$. <u>See</u> Rebuttal Testimony of William Steven Seelye at 14.

a. Is this equation to be used to allocate costs, rather than the equation that yielded an intercept of 3.14?

b. What customer-related charge does this yield?

3. Perform and submit the results of the following tests for Heteroskedasticity:

a. Glesjer Test

b. Goldfeld – Quandt Test

c. White's Test

4. Perform and submit the results that are obtained when the minimum system method is used to allocate demand and customer charges.

---

[2] Jan Kmenta, <u>Elements of Econometrics</u> 257 (MacMillan Publishing Co. 1971) (emphasis added).

5. a. What is the computed Durbin-Watson statistic? (If the Durbin-Watson statistic has not be calculated, then calculate and submit.)

b. (1) What other tests for serial correlation, if any, were performed?

(2) Provide the results of each test performed.

(3) If no other tests were performed, why not?

6. During the hearing on Delta Natural Gas Company's application, Mr. Seelye testified that the Canada Mountain Storage Field had been removed from consideration in his cost-of-service study and that inclusion of this asset would require modifications to his cost-of-service study. Provide a revised cost-of-service study that includes Canada Mountain.

QUESTIONS FOR STEVEN ESTOMIN

1. Using Mr. Seelye's data and the minimum intercept model, Commission Staff obtained the following results:

$$Y = 1.81 + 0.77X \text{ (no weighting)}^{1},$$

where Y = Unit cost ($/foot)

X = diameter of pipe (inches).

When Commission Staff used the square root of Q is used as the weight, it obtained following results:

$$\sqrt{Q_i}\,Y_i = 389.3 + 1.089(\sqrt{Q_i}\,X_i)$$

$$\sqrt{Q_i}\,Y_i = -0.15885\sqrt{Q_i} + 1.296(\sqrt{Q_i}\,X_i)$$

In his direct testimony, Dr.. Estomin obtained the predicted equation of $Y = 1.89 + 156X_i$. <u>See</u> Direct Testimony of Steven L. Estomin at 6.

a. Describe in detail how Dr. Estomin obtained his results. Show each step of the calculations and state all assumptions used.

b. Describe all transformations (e.g., scaling of data or conversions from feet to inches and vice versa) performed to obtain Dr. Estomin's results.

c. What observations, if any, were deleted? Why?

d. Why is $\Sigma w_i^2 (Y - (\alpha_i + \beta_i{*}X_i))^2$ estimated instead of $\Sigma w_i (Y - (\alpha_i + \beta_i{*}X_i))^2$? (<u>See</u> Direct Testimony of Steven L. Estomin at 5.)

---

[1] This result yields a Minimum intercept cost of $11,726,829.

e. Dr. Estomin states that this regression results in predicted equation that is given by $Y = 1.891 + 1.562^*X_i$. What customer-related charge does this predicted equation yield?

f. According to Kmenta[2], a weighted least squares equation such as $\Sigma w_i Y_i = \alpha \Sigma w_i + \beta^* X_i \Sigma w_i$ "can only be estimated if Σw_i is known and the intercept of the regression equation is zero." Given this proposition, how did Dr. Estomin obtain the intercept equal to 1.891 in the equation shown in Question 1(e)?

2. Provide the results of the following tests for Heteroskedasticity:

a. Glesjer Test

b. Goldfeld – Quandt Test

c. White's Test

3. Refer to Direct Testimony of Steven L. Estomin, Exhibit 1.

a. What are the equations that produced the negative r-square values found on pages 1, 2, 4, and 5?

b. What is the purpose for including unweighted statistics in the Exhibit?

4. Perform and submit the results that are obtained when the minimum system method is used to allocate demand and customer charges.

5. a. What is the computed Durbin-Watson statistic? (if the Durbin-Watson statistic has not be calculated, then calculate and submit.)

---

[2] Jan Kmenta, Elements of Econometrics 257 (MacMillan Publishing Co. 1971) (emphasis added).

b. (1) What other tests for serial correlation, if any, were performed?

(2) Provide the results of each test performed.

(3) If no other tests were performed, why not?

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

AN ADJUSTMENT OF RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	**CASE NO. 99-176**

* * * * * * * * * *

RESPONSE OF DELTA NATURAL GAS COMPANY, INC. TO THE ATTORNEY GENERAL'S MOTION TO STRIKE

Delta Natural Gas Company, Inc. ("Delta") respectfully submits this Response to the Attorney General's Motion to Strike and Bar from Consideration pages 49 and 50 of the rebuttal testimony of W. Steven Seelye herein, together with Seelye Rebuttal Exhibit 5. The Attorney General argues in his motion that Seelye Rebuttal Exhibit 5 is a new filing which has been improperly made and, thus, should be stricken along with the testimony explaining the exhibit. The Attorney General is mistaken and the motion should be denied.

Seelye Rebuttal Exhibit 5 and the accompanying testimony clearly rebut the arguments of the Attorney General's witness, Robert S. Henkes, that Delta's proposed Alternative Regulation Plan should be rejected because Delta could possibly "game" the budget components of the AAC factor and earn more than it is entitled to earn. While Delta's proposal to use the company's budget to formulate the AAC still is preferable, an alternative approach to formulating the AAC is to utilized Delta's actual earned return on equity for the most recent fiscal year. Seelye Rebuttal Exhibit 5 sets forth such methodology as an alternative approach which is acceptable to

Delta and which eliminates Henkes' concern that Delta might use the budget process to "game" the system. It is not intended as a tariff filing in the traditional sense of the concept, but rather as an example of an alternative approach for the formulation of the AAC.

Since Seelye Rebuttal Exhibit 5 is not a tariff filing as suggested by the Attorney General, all of the reasons for striking it and the accompanying testimony from the record are inapplicable. Thus, the motion must be denied.

Respectfully submitted,

STOLL, KEENON & PARK., LLP

Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, KY 40507
606-231-3000

Counsel for Delta Natural Gas Company, Inc.

CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by hand delivering a copy of same to Elizabeth E. Blackford, Esq. at the Public Service Commission offices on this 29th day of October 1999.

Counsel for Delta Natural Gas Company, Inc.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 29 1999
PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF)
DELTA NATURAL GAS COMPANY, INC.) CASE NO. 99-176

Response of the Attorney General to Delta Natural Gas Company's Motion to Strike the Testimony of the Attorney General's Witnesses

* *

Delta has made a variety of requests for production of documents from the Attorney General and his witnesses on matters it claims are clearly discoverable, and has deemed the Attorney General's refusal to reproduce and transport copies of the requested documents to it a violation of its rights to due process under the Fifth and Fourteenth Amendments to the United States Constitution and Sections 1 and 2 of the Kentucky Constitution. Delta's Motion is nothing more than harassment. First, Delta has no Constitutional right to discovery under either the Federal or the State Constitution. Second, there is no right to discovery outside the regulations of the Commission, which Delta failed to follow in this case. Third, Delta seeks to impose on the Attorney General obligations well in excess of the obligations attendant to the production of documents when that production is required by rule, and so cannot be heard to complain that fundamental fairness is lacking when the Attorney General's response comports with the ordinary rules.

There is no basic constitutional right to pretrial discovery in administrative proceedings.

Silverman v. Commodity Futures Trading Commission, 549 F.2d 28 at 33, 46 A.L.R. Fed. 549 (1977), copy attached. Instead, the rights to discovery in administrative proceedings are dictated by the governing statutes and regulations. Cf, Silverman, *Id.* wherein the Court points out that the Administrative Procedure act contains no provision for pretrial discovery in administrative process. Like the Administrative Procedure Act, the provisions of KRS Chapter 278 do not provide for pretrial discovery. Nevertheless, the Commission, pursuant to the power vested in it in KRS 278.040 (3) has enacted 807 KAR 5:001 Section 3 (6)(b) which provides:

> Subpoenas for the production of books, accounts, papers or records (unless directed to issue by the commission on its own authority) will be issued only at the discretion of the commission, or any commissioner, upon application in writing, stating as nearly as possible the books, accounts, papers or records desired to be produced.

Delta has not availed itself of this subpoena process, and cannot now be heard to complain.

Neither do the rules of Civil Procedure Apply to this action. Nevertheless, Delta's Motion sounds in the nature of a Civil Rule 37 Motion for Sanctions for failure to comply with a Civil Rule 34 Request for production of documents. Were Civil Rule (CR) 34 applicable, it would make it clear that the Attorney General has complied with that rule by holding the documents in the possession of those from whom they are sought available for inspection and copying in response to the production requests contained in 12, 13, 15, 16, 17, 18, 19, 20, and 21. That rule does not require the party in possession to copy and transport[1] the documents to the requesting party, but rather to

[1] It is worthy of note that the documents Delta expects the Attorney General to copy and deliver occupy approximately 13-15 linear feet of space where now housed and weight approximately 280 pounds. See the attached affidavits of Galligan, Catlin, Estomin and Henkes.

hold them available for inspection and copying. That is what witnesses Galligan, Catlin, Estomin and Henkes have agreed to do and what they continue to agree to do. Witness Weaver has also complied with that rule in his responses offered to 14 and 22 by indicating he does not possess the requested documents. One is only required to produce that which one possesses under CR 34 .

Neither is one required to produce documents of public record which are equally accessible to all parties or if the party seeking the discovery already has them in its possession. See, 23 AmJur 2d § 265 which provides:

> Discovery need not be ordered if the discovering party already has the documents in question, or if the discovering party can obtain the documents in question as readily as can the adverse party. Accordingly, discovery need not be required of documents of public record which are equally accessible to all parties.

Delta assumes an institutional organization in the Office of the Attorney General in which old testimonies are maintained in a readily accessible fashion, despite the absence of any duty to do so, which would make it easier to produce those testimonies from its files than from the records maintained by the Commission. Delta's assumption is in error. Delta is as capable of searching the files of the Public Service Commission as the Attorney General, or of placing an open records request with the Commission for the production of requested testimony and Orders to procure the information sought in data requests 10 and 11.

Delta complains that the Attorney General did not produce copies of the Orders and petitions listed by Mr. Henkes in response to data request 47 (a). No production was required as those matters were already in the hands of Delta as is evidenced by Delta's discussion of the Orders in its Experimental Alternative Regulation Plan Letter filing of February 5, 1977 at page 8. See, 23 AmJur

2d § 265.

Though there is no basic constitution right to pretrial discovery in administrative proceedings, though the regulations and statutes governing this proceeding do not support the type of discovery sought by Delta, and though the Rules of Civil Procedure pertaining to discovery are not applicable in this case, the touchstone of due process continues to be fundamental fairness. Certainly the Attorney General's actions in this proceeding comport with the notions of fundamental fairness, particularly when one considers the following:

1. Delta received the Attorney General's responses on October 15th and neither complained to the Attorney General nor sought any follow through with the Attorney General.

2. It sat on its grievance for almost two weeks without making a Motion to Compel or otherwise seeking aid from the Commission to acquire the desired information, but then came forward on the morning of the hearing crying foul and seeking the most severe penalty possible.

3. Though Delta intimates that the time period has been too short to allow it to go to the out of state site of documents, it has known since it received its copies of the testimony filed July 30th in connection with 99-046 and September 23rd in connection with 99-176 who the witnesses are and where they are located. There was nothing to prevent Delta from initiating the process of gaining timely access to the out of state sites immediately thereafter.

4. Though Delta intimates that the Attorney General has cast some undue burden on Delta by failing to copy and deliver what amounts to hundreds of pounds of documents, there is absolutely no rule, law or regulation which imposes an obligation upon the Attorney General to do that. That the Attorney General has had its witnesses hold the documents available, as would be required by Civil Rule 34 were it applicable. This more than comports with the requirements of

fundamental fairness.

5. Though Delta intimates that Carl Weaver and the Attorney General are somehow remiss based on Dr. Weaver's candid admission that he has not kept copies of 20-23 year old proceedings where he was a member of the agency before which his recommendations were made when those recommendations were made, there is nothing which demonstrates that he would have been entitled to take copies of his testimonies and recommendations with him when he left that agency, much less that he had any obligation to do so. Fundamental fairness is not offended.

6. The short turn around times which Delta now complains of are the direct result of the Commission's effort to accommodate Delta's oft repeated plea for speed in this proceeding. The entire schedule has been compressed in an effort to do that which Delta asks. That the schedule has therefore left Delta pressed for time to do all that it would like by way of preparatory investigation in no way offends fundamental fairness.

Wherefore, the Attorney General prays the Commission to overall Dismiss Delta's Motion to Strike and to continue this proceeding to its conclusion.

Respectfully Submitted,

EEB

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

CERTIFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that this the 29th day of October, 1999 I have filed the Original and eight copies of the foregoing with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and further certify that this same day I have served the parties by hand delivery of a true copy to the Hon. Robert Watt at 730 Schenkel Lane, Frankfort, Kentucky, 40601.

Assistant Attorney General

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF)
DELTA NATURAL GAS COMPANY, INC.) CASE NO. 99-176

Affidavit

Comes the Affiant, Robert J. Henkes and being duly sworn states that as currently housed his prior testimonies occupy 4-5 linear feet and weigh an estimated 50 pounds.

Further Affiant Saith Not.

Commonwealth of Kentucky
County of Franklin

Subscribed before me this the 29th day of October, 1999, by Robert J. Henkes.

MY COMMISSION EXPIRES: 10/14/2002

Notary Public, State at Large

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-176

Affidavit

Comes the Affiant, Richard A. Galligan and being duly sworn states that as currently housed his prior testimonies occupy an estimated 2-3 linear feet and weigh an estimated 100 pounds.

Further Affiant Saith Not.

Richard A. Galligan

Commonwealth of Kentucky
County of Franklin

Subscribed before me this the 29th day of October, 1999, by Richard A. Galligan.

MY COMMISSION EXPIRES: 10/14/2002

Notary Public, State at Large

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF)
DELTA NATURAL GAS COMPANY, INC.) CASE NO. 99-176

Affidavit

Comes the Affiant, Steven Estomin and being duly sworn states that as currently housed his prior testimonies occupy an estimated 2 linear feet and weigh an estimated 20 pounds.

Further Affiant Saith Not.

Steven Estomin

Commonwealth of Kentucky
County of Franklin

Subscribed before me this the 29th day of October, 1999, by Steven Estomin.

MY COMMISSION EXPIRES: 10/14/2002

Notary Public, State at Large

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-176

Affidavit

Comes the Affiant, Thomas Catlin and being duly sworn states that as currently housed his prior testimonies occupy an estimated 5 linear feet and weigh an estimated 100 pounds.

Further Affiant Saith Not.

Thomas S. Catlin

Commonwealth of Kentucky
County of Franklin

Subscribed before me this the 29th day of October, 1999, by Thomas Catlin.

MY COMMISSION EXPIRES: 10/14/2002

Notary Public, State at Large

*28 549 F.2d 28

46 A.L.R.Fed. 549

Jeffrey L. SILVERMAN, Petitioner,
v.
COMMODITY FUTURES TRADING COMMISSION, Respondent.

No. 76-1469.
United States Court of Appeals,
Seventh Circuit.
Argued Jan. 21, 1977.
Decided Feb. 16, 1977.

Account executive in the commodity brokerage business petitioned for review of order of the Commodity Futures Trading Commission suspending trading privileges on commodity futures markets. The Court of Appeals, Sprecher, Circuit Judge, held that evidence supported administrative law judge's finding that petitioner wilfully violated section of CFTC Act making it unlawful to cheat or defraud or attempt to cheat or defraud any person in connection with any contract of sale of any commodity for future delivery; that denial of petitioner's motion to dismiss the complaint on ground that he was unable to obtain and use for purposes of hearing the agency's internal nonpublic guidelines relating to conduct of investigations so as to prepare a line of defense or to properly cross-examine the investigators was not a denial of due process; and that denial of request for statement of procedure employed by investigators in interrogating customers and to take depositions of the investigators and to show that investigators deviated from the administrative guidelines did not constitute a deprivation of due process in light of the whole record.

Affirmed.

1. COMMODITY FUTURES TRADING REGULATION k60
83H ----
83HII Administrative Agencies, Proceedings, and Orders
83Hk60 Judicial review.

Formerly 160k5(2)
C.A.7 1977.
Court reviewing order of Commodity Futures Trading Commission cannot substitute its views of credibility for that of the administrative law judge. Commodity Exchange Act, Secs. 1-12 as amended 7 U.S.C.A. Secs. 1-17a.

2. COMMODITY FUTURES TRADING REGULATION k30
83H ----
83HI Regulation in General
83Hk30 Evidence.

Formerly 160k5(2)
C.A.7 1977.
Evidence supported administrative law judge's finding that petitioner, an account executive in the commodity brokerage business whose trading privileges on commodity futures markets were suspended, wilfully violated section of CFTC Act making it unlawful for any member of a contract market in connection with making any contract of sale of any commodity for future delivery to cheat or defraud or attempt to cheat or defraud any person. Commodity Exchange Act, Sec. 4b as amended 7 U.S.C.A. Sec. 6b.

3. ADMINISTRATIVE LAW AND PROCEDURE k441
15A ----
15AIV Powers and Proceedings of Administrative Agencies, Officers and Agents
15AIV(D) Hearings and Adjudications
15Ak441 In general.
C.A.7 1977.
There is no basic constitutional right to pretrial discovery in administrative proceedings.

4. ADMINISTRATIVE LAW AND PROCEDURE k441
15A ----
15AIV Powers and Proceedings of Administrative Agencies, Officers and Agents
15AIV(D) Hearings and Adjudications
15Ak441 In general.
C.A.7 1977.
The Administrative Procedure Act contains no provision for pretrial discovery in the administrative process. 5 U.S.C.A. Sec. 552.

5. ADMINISTRATIVE LAW AND PROCEDURE k441
15A ----
15AIV Powers and Proceedings of

Administrative Agencies, Officers and Agents
15AIV(D) Hearings and Adjudications
15Ak441 In general.
C.A.7 1977.
Federal Rules of Civil Procedure for discovery do not apply to administrative proceedings.

6. CONSTITUTIONAL LAW k296(1)
92 ----
92XII Due Process of Law
92k296 Regulation of Trade, Business, or Profession
92k296(1) In general.

Formerly 92k318(2)
C.A.7 1977.
Where petitioner, an account executive whose trading privileges on commodity futures market were suspended, was provided in advance of administrative hearing with copies of all proposed exhibits, a list of all proposed witnesses, the identity of government employees who had investigated the case and copies of memoranda reflecting petitioner's own statements to administrative representatives, petitioner was not denied due process in regard to the prehearing production of documents by the CFTC. Commodity Exchange Act, Secs. 1-12, 4, 4b, 4d, 4e, 4k, 4m, 5 as amended 7 U.S.C.A. Secs. 1-17a, 6, 6b, 6d, 6e, 6k, 6m, 7.

7. CONSTITUTIONAL LAW k296(1)
92 ----
92XII Due Process of Law
92k296 Regulation of Trade, Business, or Profession
92k296(1) In general.

Formerly 92k318(2)
C.A.7 1977.
Denial of petitioner's motion to dismiss or to reopen administrative hearing on charges of violation of CFTC Act, on ground that petitioner was unable to obtain requested information to prepare a line of defense or to cross-examine investigators, was not a denial of due process. Commodity Exchange Act, Secs. 1-12, 4, 4b, 4d, 4e, 4k, 4m, 5 as amended 7 U.S.C.A. Secs. 1-17a, 6, 6b, 6d, 6e, 6k, 6m, 7.

8. COMMODITY FUTURES TRADING REGULATION k56
83H ----
83HII Administrative Agencies, Proceedings, and Orders
83Hk56 Proceedings in general; notice.

Formerly 160k5(2)
C.A.7 1977.
Although the Jencks Act applies only in criminal prosecutions, Act was complied with in administrative hearing on violations of CFTC Act where petitioner was furnished during course of hearings with witnesses' statements and reports of interviews with them. Commodity Exchange Act, Sec. 4b as amended 7 U.S.C.A. Sec. 6b; 18 U.S.C.A. Sec. 3500.

9. COMMODITY FUTURES TRADING REGULATION k56
83H ----
83HII Administrative Agencies, Proceedings, and Orders
83Hk56 Proceedings in general; notice.

Formerly 160k5(2)
C.A.7 1977.
At administrative hearing on charge of violating CFTC Act, petitioner was not entitled to statements of procedure employed by investigators in interrogating customers, or to take depositions of investigators or to show that the investigators deviated from the administrative guidelines. Commodity Exchange Act, Sec. 4b as amended 7 U.S.C.A. Sec. 6b.

10. UNITED STATES k133
393 ----
393IX Actions
393k133 Time to sue, limitations, and laches.
C.A.7 1977.
The United States was not subject to doctrine of laches for alleged delay in filing complaint charging account executive with violating CFTC Act. Commodity Exchange Act, Sec. 4b as amended 7 U.S.C.A. Sec. 6b.

***29** Joel J. Bellows, Charles B. Bernstein, Chicago, Ill., for petitioner.

Howard Schneider and Joan Loizeaux, Commodity Futures Trading Commission, Washington, D. C., for respondent.

Before CUMMINGS, PELL and SPRECHER, Circuit Judges.

SPRECHER, Circuit Judge.

This appeal tests the validity of a suspension of trading privileges on commodity futures markets imposed upon an account executive in the commodity brokerage business.

I

The Commodity Futures Trading Commission (CFTC or Commission) is an independent federal regulatory agency which began operating on April 21, 1975, pursuant to the Commodity Futures Trading Commission Act of 1974 (CFTC Act or Act), Pub.L.No.93-463, 88 Stat. 1389, et seq., which amended the Commodity Exchange Act, 7 U.S.C. ss 1-17a.

The CFTC's principal responsibility relates to contracts of sale of commodities for future delivery traded or executed on boards of trade, that is, commodity exchanges which have been designated by the Commission as "contract markets" for specific commodity futures contracts. 7 U.S.C. s 7. It is unlawful to affect a commodity futures transaction other than by or through a member of a "contract market." 7 U.S.C. s 6.

All futures commission merchants (7 U.S.C. s 6d), floor brokers (s 6e), persons associated with futures commission merchants (s 6k), commodity trading advisors and commodity pool operators (s 6m) must register with the CFTC.

The Commission is entrusted with enforcing the regulatory requirements and proscriptions of the Act against registrants and other persons subject to the Act. One of the statutory provisions which the Commission enforces is section 4b, 7 U.S.C. s 6b, which makes it "unlawful . . . for any member of a contract market . . . or employee of any member . . . in or ***30** in connection with any order to make, or the making of, any contract of sale of any commodity for future delivery, made, or to be made, on or subject to the rules of any contract market, for or on behalf of any other person . . . to cheat or defraud or attempt to cheat or defraud such other person." (FN1)

On March 13, 1973, a complaint was brought before the Secretary of Agriculture, alleging violations by the petitioner, Jeffrey L. Silverman, of section 4b of the CFTC Act. On May 5, 1976, a final order was entered by the CFTC, prohibiting the petitioner from trading on or subject to the rules of any contract market for a period of two years. The petitioner was also ordered to permanently cease and desist from placing, or causing to be placed, in any customer's account, any contracts of sale of any commodity for future delivery, without the prior knowledge, consent or authorization of such customer.

The petitioner filed his petition for review of the final order pursuant to 7 U.S.C. s 9, contending that (1) the evidence does not support the finding of willful violation of section 4b of the Act; (2) the petitioner was denied due process by the arbitrary conduct of the CFTC; and (3) the CFTC violated its operational guidelines.

II

In Great Western Food Distributors, Inc. v. Brannan, 201 F.2d 476, 479-80 (7th Cir. 1953), this court delineated the scope of appellate review in a case of the suspension of commodity trading privileges under the Commodity Exchange Act:

> Often the "most telling part" of the evidence is not apparent from the printed page, "for on the issue of veracity the bearing and delivery of a witness will usually be the dominating factors". N.L.R.B. v. Universal Camera Corp., 2 Cir., 190 F.2d 429, 430. Thus, "we may not disregard the superior advantages of the examiner who heard and saw the witnesses for determining their credibility, and so for ascertaining the truth." Ohio Associated Tel. Co. v. N.L.R.B., 6 Cir., 192 F.2d 664, 668.
>
> It would seem, then, that the function of this court is something other than that of mechanically reweighing the evidence to ascertain in which direction it preponderates; it is rather to review the record with the purpose of determining whether the finder of the fact was justified, i. e. acted reasonably, in concluding that the evidence, including the demeanor of the ***31** witnesses, the reasonable inferences drawn therefrom and other pertinent circumstances, supported his findings. To go further is to disregard the "most telling part" of the evidence.

The petitioner contended that the Commission failed to give him notice of the alleged misconduct and an opportunity to achieve compliance in accordance with section 9(b) of the Administrative Procedure Act, which provides in pertinent part, 5 U.S.C. s 558(c):

Except in cases of willfulness . . . , the withdrawal, suspension, revocation, or annulment of a license is lawful only if, before the institution of agency proceedings therefor, the licensee has been given

(1) notice by the agency in writing of the facts or conduct which may warrant the action; and

(2) opportunity to demonstrate or achieve compliance with all lawful requirements. (Emphasis added.)

The same argument was made by a commodities dealer in Goodman v. Benson, 286 F.2d 896, 900 (7th Cir. 1961), where we held that section 9(b) was inapplicable by its terms to willful cases and said:

We think it clear that if a person 1) intentionally does an act which is prohibited, irrespective of evil motive or reliance on erroneous advice, or 2) acts with careless disregard of statutory requirements, the violation is wilful.

The Administrative Law Judge made several findings and conclusions relating to petitioner's willfulness:

There is no room to consider that the trades made were the product of innocent mutual or unilateral mistake or misunderstanding. They were clearly the results of a pattern and program of trading in large measure carried on over a period of years with many people in an intentional and calculated manner by (Silverman). ALJ's Decision, p. 25; emphasis added.

The record suggests that unauthorized trading, as here, is common enough for (Silverman) to feel comfortable in it, and to attempt to justify it by volatile market conditions creating or destroying opportunities for profitable trades too swiftly to contact a client. ALJ's Decision, pp. 20-21.

By reason of the facts and conclusions as set forth, (Silverman) has wilfully violated section 4b of the Commodity Exchange Act . . . as charged. ALJ's Decision, p. 26.

The findings and conclusions indicated that the petitioner's conduct was willful under either part of the definition set out in Goodman v. Benson, supra. Furthermore, the ALJ's findings and conclusions regarding the petitioner's willfulness are fully supported by the record.

The CFTC Act was designed to insure "fair practice and honest dealing on the commodity exchanges." (FN2) Hearings were held before the Administrative Law Judge on six days in February and March, 1974, consuming 1211 pages of transcript. The record revealed that the petitioner was employed from July 1969 to October 1970, as an account executive with the commodity brokerage firm of Woodstock, Inc. and from October 1970 to March 13, 1972 with the firm of Conti-Commodity Services. The petitioner was charged with entering into 23 unauthorized transactions with three Woodstock customers (Borgers, Tuczai and Stengel) and with two Conti customers (Barbiere and McGuire).

Borgers went on an extended vacation in the summer of 1970 and gave the petitioner authority to make trades on his account in live cattle, live hogs and pork bellies. Although the petitioner had no authority to *32 make egg transactions on Borgers' behalf, the petitioner made an egg trade on August 18, 1970, to which Borgers objected. Thereafter, despite Borgers' express direction that no egg trades be made, the petitioner proceeded to make eight unauthorized egg transactions on Borgers' account.

Tuczai instructed the petitioner in March 1970 not to make any trades without his specific permission. Nevertheless in October 1970, the petitioner made six unauthorized egg transactions on Tuczai's account.

Stengel had previously experienced some difficulties relating to unauthorized trading by a Woodstock solicitor and therefore instructed the petitioner that no trades were to be made without his express prior consent. Despite that fact the petitioner made four unauthorized egg trades and one unauthorized hog trade on Stengel's behalf.

[1] The petitioner testified that he had oral authority from Borgers, Tuczai and Stengel in regard to the 18 egg transactions and that the Stengel hog transaction was consummated as an offset because one of Stengel's checks had bounced in

connection with an authorized hog transaction. The ALJ did not credit the petitioner's testimony but did credit the countervailing testimony. We cannot substitute our views of credibility for that of the ALJ, assuming that we were so inclined.

Barbiere, one of the Conti customers, testified that he did not believe that he authorized two pork belly contracts and one London sugar contract on March 9, 1972 "but . . . (the petitioner) could have misinterpreted (a conversation) as an authorization." These transactions were not found by the ALJ to be violations by the petitioner. However, a few days later, a March 13, 1972 hog belly transaction was completely unauthorized by Barbiere and was found to be a violation.

The petitioner contended that all of Barbiere's transactions were authorized because he had signed a "Trading Authorization Limited to Purchases and Sales of Commodities." Barbiere testified that he understood the document which he had signed to be a mere authorization for the petitioner to make trades for him after specific authorization had been given to make specific trades. (FN3) He further testified that he had refused to sign a general power of attorney. (FN4)

The ALJ made the following findings and conclusions in this regard (ALJ's Decision, p. 17):

> The flat refusal by Barbiere to sign a power of attorney is clear indication of his state of mind, and is persuasive that he intended to retain full control over his account. The signature on the "Trading Authorization" form was obtained without informed consent by Barbiere. Further, the account did not meet the CME rules for controlled or managed accounts in regard to financial or other requirements.

In Geldermann & Co., Inc. v. Lane Processing, Inc., 527 F.2d 571, 575-76 (8th Cir. 1975), the court, after giving consideration to the fact that "when a party of little bargaining power, and hence little real choice, signs a commercially unreasonable contract with little or no knowledge of its *33 terms it is hardly likely that his consent, or even an objective manifestation of his consent, was ever given to all the terms," held that the terms of a commodities signature card gave a commodities broker the authority to make certain transactions where the customer had a net worth of $7,000,000 and "was a sophisticated investor and entrepreneur." Here the petitioner conceded that "Barbiere was a novice in commodity trading." Pet. Reply Br. 7.

The other Conti customer, McGuire, testified that the petitioner had made three unauthorized pork belly transactions in March 1972, on his account. The petitioner again testified that he had been given verbal authorization and also that McGuire had sent in a written "Trading Authorization." However, whereas the petitioner had produced Barbiere's written authorization, he did not produce any written authorization from McGuire. The petitioner's arguments relating to oral authorization by both Barbiere and McGuire merely amount to attacks on the ALJ's credibility determinations, which we cannot overturn.

[2] In summary, we find that the evidence amply supports the ALJ's finding that the petitioner willfully violated section 4b of the CFTC Act.

III

The petitioner has argued that he was denied due process during the administrative proceedings in several ways, many of which relate to the prehearing production of documents by the CFTC.

[3][4][5] There is no basic constitutional right to pretrial discovery in administrative proceedings. Starr v. Commissioner of Internal Revenue, 226 F.2d 721, 722 (7th Cir. 1955), cert. denied, 350 U.S. 993, 76 S.Ct. 542, 100 L.Ed. 859 (1955); N.L.R.B. v. Interboro Contractors, Inc., 432 F.2d 854, 857 (2d Cir. 1970). The Administrative Procedure Act contains no provision for pretrial discovery in the administrative process (1 Davis, Administrative Law Treatise (1958) s 8.15, p. 588) and the Federal Rules of Civil Procedure for discovery do not apply to administrative proceedings (N.L.R.B. v. Vapor Blast Mfg. Co., 287 F.2d 402, 407 (7th Cir. 1961)). The regulations of the Commodity Exchange Authority of the Department of Agriculture did not provide, at the time of the administrative hearing, for prehearing discovery.

Nevertheless the due process clause does insure the fundamental fairness of the administrative hearing. We have said:

> True it is that administrative convenience or even necessity cannot override the constitutional

requirements of due process. Ohio Bell Telephone Co. v. Public Utilities Commission of Ohio, 301 U.S. 292, 304, 57 S.Ct. 724, 81 L.Ed. 1093. However, in administrative hearings the hearing examiner has wide latitude as to all phases of the conduct of the hearing, including the manner in which the hearing will proceed. Radio Corp. of America v. United States, 341 U.S. 412, 420, 71 S.Ct. 806, 95 L.Ed. 1062; Wallace v. N.L.R.B., supra, 323 U.S. 248 at page 253, 65 S.Ct. 238 at page 240, 89 L.Ed. 216; N.L.R.B. v. Algoma Plywood & Veneer Co., 7 Cir., 121 F.2d 602, 604. Administrative agencies should be "free to fashion their own rules of procedure and to pursue methods of inquiry capable of permitting them to discharge their multitudinous duties." Federal Communications Comm. v. Pottsville Broadcasting Co., 309 U.S. 134, 143, 60 S.Ct. 437, 441, 84 L.Ed. 656.

Cella v. United States, 208 F.2d 783, 789 (7th Cir. 1953); see also, Swift & Co. v. United States, 308 F.2d 849, 852 (7th Cir. 1962) (and at 851: "Due process in an administrative hearing, of course, includes a fair trial, conducted in accordance with fundamental principles of fair play and applicable procedural standards established by law.")

[6] The petitioner was provided in advance of the hearing with copies of all proposed exhibits, a list of all proposed witnesses, the identity of the government employees who had investigated the case and copies of memoranda reflecting petitioner's own statements to administrative representatives.

*34 [7] The petitioner also sought under the Freedom of Information Act, 5 U.S.C. s 552, the agency's internal non-public guidelines relating to the conduct of investigations. The three such guidelines which were applicable to the investigation of the kind involved herein were furnished to the petitioner prior to the hearing. Upon the petitioner's filing of a proceeding in the federal district court for the Northern District of Illinois under the Freedom of Information Act, the agency voluntarily provided the petitioner with all of the remaining guidelines, but this occurred after the administrative hearing. The petitioner then moved to dismiss the complaint, merely stating that he "was unable to obtain and use for the purposes of that hearing, the requested information so as to prepare a line of defense or to properly cross-examine the investigators who participated in the preparation of the case." Prior to rendering his decision and order, the Administrative Law Judge denied the petitioner's motion to dismiss, stating in part:

(Silverman) . . . fails to make any showing of the subject matter to be explored in the requested supplemental cross-examination opportunities, its relationship to the issues herein, the relevancy or materiality to said issues . . . and the relative merit or prejudice expected to be established by it. (Silverman) . . . fails to show that it would be anything other than merely cumulative, and that it involves anything other than speculation and hypothesis.

For all of these reasons, the denial of the petitioner's motion to dismiss, or in the alternative to reopen, the proceedings was not a denial of due process. Administrative proceedings would become a shambles if they could be reopened upon mere request and without a supportive showing of need.

[8] The petitioner also sought copies of statements received from customers and reports the administrative investigators had prepared concerning their interviews with customers. Although the Jencks Act, 18 U.S.C. s 3500, applies by its terms only "in any criminal prosecution brought by the United States," the agency here complied with the Act's requirements that statements of witnesses be produced after the witnesses have testified on direct examination, by furnishing the petitioner during the course of the hearing with witnesses' statements and reports of interviews with them.

[9] The petitioner also complained that he was entitled (1) to "a statement of the procedure employed by . . . (the investigators) in interrogating the five customers," (2) to take depositions of the investigators, and (3) to show that the investigators deviated from the administrative guidelines. The denial of these requests did not constitute deprivation of due process in the light of the whole record. Obviously an administrative hearing cannot be diverted into a trial of the mechanics of the preliminary investigation unless some flagrant abuses are shown, and such a showing could be made upon cross-examination of the witnesses during the hearing. Nor is it necessary for an investigator to scrupulously adhere to each detail of a "guideline." Every investigation must necessarily differ from all others and guidelines are only that.

Guidelines are intended to generally facilitate the business of the agency and not as conferring important procedural benefits upon the subjects of investigation. American Farm Lines v. Black Ball Freight Service, 397 U.S. 532, 538-39, 90 S.Ct. 1288, 25 L.Ed.2d 547 (1970); United States v. Lockyer, 448 F.2d 417, 420-21 (10th Cir. 1971).

[10] The petitioner also invoked the doctrine of laches because (1) the violations occurred in 1970 and 1972 whereas the complaint was filed on March 13, 1973, and (2) the hearing file was submitted to the Administrative Law Judge on December 30, 1974 whereas his decision was filed on December 30, 1975. "It is well settled that the United States is not bound by state statutes of limitation or subject to the defense of laches in enforcing its rights." United States v. Summerlin, 310 U.S. 414, 416, 60 S.Ct. 1019, 1020, 84 L.Ed. 1283 (1940).

Finally, the petitioner has raised numerous other issues, all of which we have considered *35. and deem to be without merit. In particular, we find the various rulings of the Administrative Law Judge before, during and after the hearing to be well within his sound discretion and not constituting any deprivation of due process.

For these reasons the order of the Commodity Futures Trading Commission should be affirmed.

AFFIRMED.

FN1. 7 U.S.C. s 6b provides in fuller part:

It shall be unlawful (1) for any member of a contract market, or for any correspondent, agent, or employee of any member, in or in connection with any order to make, or the making of, any contract of sale of any commodity in interstate commerce, made, or to be made, on or subject to the rules of any contract market, for or on behalf of any other person, or (2) for any person, in or in connection with any order to make, or the making of, any contract of sale of any commodity for future delivery, made, or to be made, on or subject to the rules of any contract market, for or on behalf of any other person if such contract for future delivery is or may be used for (a) hedging any transaction in interstate commerce in such commodity or the products or by-products thereof, or (b) determining the price basis of any transaction in interstate commerce in such commodity, or (c) delivering any such commodity sold, shipped, or received in interstate commerce for the fulfillment thereof

(A) to cheat or defraud or attempt to cheat or defraud such other person;

(B) willfully to make or cause to be made to such other person any false report or statement thereof, or willfully to enter or cause to be entered for such person any false record thereof;

(C) willfully to deceive or attempt to deceive such other person by any means whatsoever in regard to any such order or contract or the disposition or execution of any such order or contract, or in regard to any act of agency performed with respect to such order or contract for such person; or

(D) to bucket such order, or to fill such order by offset against the order or orders of any other person, or willfully and knowingly and without the prior consent of such person to become the buyer in respect to any selling order of such person, or become the seller in respect to any buying order of such person.

FN2. S.Rep.No.93-1131, 93d Cong., 2d Sess. (Aug. 29, 1974), U.S.Code Cong. & Adm.News, 93d Cong., 2d Sess. at 5844 (1974): "The bill is designed to further the fundamental purpose of the Commodity Exchange Act in insuring fair practice and honest dealing on the commodity exchanges and providing a measure of control over those forms of speculative activity which often demoralize the markets to the injury of producers, consumers, and the exchanges themselves."

FN3. Barbiere testified: "I understood that document . . . (that) he would be acting as my agent to make purchases." (Tr. 299).

"(M)y interpretation, an agent who would be able to make these purchases for me. The only understanding I would be notified prior to making any of these transactions. That was my understanding of what that document meant . . ." (Tr. 300).

FN4. Barbiere testified: "When the discussion of power of attorney was brought to my attention I flatly refused. I felt this wasn't the situation I wanted to be involved with."

"(Silverman) asked me at that time when I opened the account whether or not, you know, how I felt about it. I was very strongly against (a power of attorney). I believe very firmly that . . . I should have the privilege of making my own mistakes and pay for them. This is the reason I didn't elect to give the power of attorney. . . . I felt for the type of thing I participated in there would be no use for that speed." (Tr. 270).

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 28, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

ORDER

The Attorney General ("AG") has moved for an enlargement of time to respond to the information requests of Delta Natural Gas Company ("Delta"). No objection to this motion has been filed with the Commission. Having considered the motion, the Commission finds that good cause exists to grant the requested enlargement of time.

IT IS THEREFORE ORDERED that:

1. The AG's Motion for Enlargement of Time is granted.

2. The AG is granted an additional day to respond to Delta's information requests.

Done at Frankfort, Kentucky, this 28th day of October, 1999.

By the Commission

ATTEST:

Executive Director

RECEIVED

OCT 28 1999

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

AN ADJUSTMENT OF RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	**CASE NO. 99-176**

* * * * * * * * * *

MOTION OF DELTA NATURAL GAS COMPANY, INC. TO STRIKE TESTIMONY OF ATTORNEY GENERAL'S WITNESSES

Delta Natural Gas Company, Inc. ("Delta") respectfully moves the Commission for the entry of an order striking the testimony of the following witnesses of the Attorney General herein: Carl G.K. Weaver, Robert S. Henkes, Thomas S. Catlin, Richard A. Galligan, and Steven L. Estomin. In support of the foregoing motion, Delta states that the Attorney General failed and refused to provide documents requested by Delta in its October 4, 1999, Request for Information to the Attorney General herein, which documents are clearly discoverable and may contain information necessary to enable Delta to conduct cross-examination of the foregoing witnesses and otherwise present its case. As a result, the Attorney General should not be permitted to offer testimony by the foregoing witnesses as Delta has been denied its rights under the Fifth and Fourteenth Amendments to the United States Constitution and Sections 1 and 2 of the Kentucky Constitution.

In its Request for Information to the Attorney General herein, Delta specifically requested the Attorney General to furnish copies of the documents responsive to the Requests for

Information rather than refer Delta to the location of the documents. This request was made because Delta had neither the time nor the resources to go find documents which are in the possession of the Attorney General or his witnesses. The Attorney General's responses to Delta's Requests for Information were received by Delta and its counsel on Friday afternoon, October 15, 1999. Delta needed to obtain documents responsive to the following requests for information because the Attorney General refused to produce them with his response: Item 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22 and 47(a). Delta's rebuttal testimony was due on Monday, October 25, 1999. Thus, Delta had only a total of ten days, of which only five days were business days, to seek and obtain the documents responsive to Delta's requests before the rebuttal testimony was due. It had only thirteen days, of which only eight days were business days, to seek and obtain the documents before the hearing date herein.

Item 10 sought copies of the testimony of the Attorney General's witnesses before this Commission in the last ten years. The Attorney General objected on the grounds that the documents are equally available to Delta as to the Attorney General. That is not so. Only two witnesses, Henkes and Weaver, have testified before this Commission. Surely they and the Attorney General have copies of their testimony which can be copied and sent to Delta far more easily than Delta can search for the cases and obtain copies of the testimony from the Commission. Item 11 sought copies of the orders in the cases in which the Attorney General's witnesses have testified in Kentucky. The Attorney General again refused to produce the documents. The same reasoning applies to Item 11 as to Item 10.

Items 12, 13 and 16 sought copies of testimony offered by Catlin, Galligan and Estomin, respectively, in cases involving gas utilities or combination gas utilities. The Attorney General responded that the documents were voluminous and offered to make them available at the offices of Exeter Associates, Inc., Catlin's, Galligan's and Estomin's firm, in Silver Spring, Maryland. Item 14 sought the same testimony from Weaver. The Attorney General responded that Weaver does not maintain copies of his testimonies; however, one would expect that the Attorney General has copies of the testimony presented on prior occasions on which Weaver has testified on behalf of the Attorney General in Kentucky. Those documents were not produced or offered. Item 15 sought the same testimony from Henkes. Again, the Attorney General responded that the documents were voluminous and offered to make them available at Henkes' offices, which are located in Old Greenwich, Connecticut.

Item 17 sought copies of all gas cost of service studies prepared by Catlin. Again, the Attorney General only offered to allow Delta to go to Silver Spring, Maryland, and look for the documents at Catlin's office. Item 18 sought copies of all gas cost of service studies prepared by Galligan. The Attorney General made the same response as he did to Item 17. Item 19 sought Galligan's electric cost of service studies. The Attorney General offered the information that Galligan had not prepared one in the last ten years and again offered to let Delta go to Maryland to look for the documents. Items 20 and 21 sought copies of all testimony presented by Catlin and Galligan, respectively, that deals with the allocation of costs in a rate case. Again, the Attorney General failed to produce the documents and referred Delta to the Maryland offices of the witnesses.

Item 22 sought copies of testimony submitted by Weaver which recommended the use of a hypothetical or imputed capital structure in any proceeding before any regulatory agency. In his response to this data request Weaver stated that, "when I [sic] Director of the Economic Research and Development Division of the State of Virginia State Corporation Commission, I recommended the use of a hypothetical capital structure in situations where the applicant company's capital structure was different from a typical capital structure for an industry." This statement leads Delta to believe that Weaver may have submitted testimony supporting a position very similar to the one that Delta is taking in this proceeding. As the Commission is well aware, the use of an imputed capital structure is a key issue in this proceeding and the Attorney General should not be permitted to deny Delta's right to this critical information.

Item 47(a) requested copies of all information Henkes reviewed concerning the PBR mechanisms of Columbia Gas, Western Kentucky Gas and LG&E in order to draw the conclusions expressed in his testimony about those PBR mechanisms in comparison to Delta's Alt Reg Plan. The Attorney General identified orders and other parts of the records in those cases and refused to produce the documents on the grounds that Delta could just as easily go get them at the Commission. Again, the Attorney General or his witness clearly had copies of the documents in order to identify them and simply refused to produce them. His approach is not fair.

The information sought in the foregoing requests for information is clearly discoverable in every sense of the word (as evidenced by the failure of the Attorney General to object on the grounds that it is not discoverable). The documents may very well contain prior inconsistent statements of the witnesses or other information which may be helpful to Delta in its cross-examination of the Attorney General's witnesses. Thus, it is a routine matter in litigation or administrative proceedings involving expert witnesses, like the Attorney General's witnesses here, to obtain copies of prior testimony or prior publications involving the subject matter of the proceeding in which their testimony is offered. Here, the Commission's procedural schedule makes it impossible, as a practical matter, for Delta to travel to Connecticut and Maryland to inspect documents, obtain copies, return to Kentucky and still prepare rebuttal testimony and prepare for the hearing. Thus, by making the seemingly benign offer to produce the documents at the witnesses' offices, the Attorney General has denied Delta discovery of the requested documents.

Delta has been prejudiced by the failure of the Attorney General to make the requested discovery because he may be withholding information helpful to Delta in its cross-examination of the Attorney General's witnesses and otherwise helpful in the presentation of its case. Delta cannot afford to amend the procedural schedule to permit the Attorney General additional time to produce the documents because each day which passes without rate relief represents lost revenue for Delta and the winter heating season begins the Monday after the hearing. Indeed, Delta cannot and, therefore does not, agree to any modification of the procedural schedule. Therefore, the only fair resolution of the issue is to strike the testimony of the Attorney General's witnesses.

These requests for information, or ones very similar to them, are propounded in every rate case in Kentucky. The Attorney General should advise his witnesses to send all such prior testimony, publications, cost of service studies and the like to the Attorney General's office before filing testimony so that the documents can be made available promptly after filing the testimony. Otherwise, applicants, like Delta, are unable, because of time and financial restraints, to obtain discovery to which they are entitled.

The course followed by the Attorney General here gives him an unfair advantage and should not be permitted. The testimony should be stricken and disregarded by the Commission and its staff.

Respectfully submitted,

STOLL, KEENON & PARK, LLP

By Robert Watt

Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, KY 40507
606-231-3000

Counsel for Delta Natural Gas Company, Inc.

CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by hand delivering a copy of same to the following person on this 28th day of October 1999:

Elizabeth E. Blackford, Esq.
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601-8204

Robert Watt

Robert M. Watt, III

RECEIVED

OCT 28 1999

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF)
DELTA NATURAL GAS COMPANY, INC.) CASE NO. 99-176

MOTION TO STRIKE AND TO BAR FROM CONSIDERATION

* *

Comes the Attorney General and moves the Commission to strike those portions of the rebuttal testimony of Steven Seele contained at pages 49 through 50 pertaining to an alternative means for the determination of the AAC factor (which would utilize factors other than the previously proposed budget as the basis for establishing the factor) and the AAF factor (which would newly incorporate the imputed capital structure previously proposed only in conjunction with the establishment of rates under the general rate case) of the proposed Alternative Regulation Plan, and accompanying revised tariff contained in Seele Rebuttal Exhibit 5 on the grounds that it is a new filing whose consideration is sought despite the fact that (1) no notice has been given pertaining to this newly formulated alternative regulation mechanism which differs from the matters to be heard as previously advertised by Delta; (2) the offer raises new issues which are not appropriate for consideration by way of rebuttal; (3) consideration of the proposal would offend due process as the Attorney General will be unable to conduct discovery pertaining to the proposal, to offer proof concerning the proposal or to be fully heard pertaining to the proposal which first appears in the record three days before the hearing is to begin.

Respectfully Submitted,

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

Certificate of Service and Notice of Filing

I hereby give notice that this the 28th day of October, 1999 the original and eight copies of the foregoing have been filed with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and certify that a copy of same has been hand delivered the parties by hand delivering a copy to Counsel for Delta, Hon. Robert Watt at the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky on this same day.

COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

ALBERT B. CHANDLER III
ATTORNEY GENERAL

1024 CAPITAL CENTER DRIVE
FRANKFORT, KY 40601-8204

October 19, 1999

RECEIVED
OCT 27 1999
PUBLIC SERVICE COMMISSION

Honorable Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
Frankfort, Kentucky 40601

RE: In Re the Matter of: Adjustment of Rates of Delta Natural Gas Company Inc., Administrative Case No. 99-176

Dear Ms. Helton,

To clarify the record, I hereby give notice that the attachments responsive to Data Request 26 of to the Public Service Commission Order of October 4, 1999, were not included as a part of that response, but are included in the record as the attachment to the response to data request number 83 of the Request for Information Propounded to the Attorney General by Delta Natural Gas Company, Inc.

Respectfully Submitted,

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

cc: Robert M. Watt, III
John F. Hall

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JAMES PARK (1892 - 1970)
JOHN L. DAVIS (1913 - 1970)
GEADNEY HARVILLE (1921 - 1978)
GAYLE A. MOHNEY (1906 - 1980)
C. WILLIAM SWINFORD (1921 - 1986)

October 25, 1999

Hon. Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

Re: Delta Natural Gas Company, Inc.
Case No. 99-176

Dear Ms. Helton:

We deliver herewith for filing ten (10) copies of the rebuttal testimony of W. Steven Seelye, Martin J. Blake and John B. Brown in the above-captioned case. We would appreciate your placing the testimony with the other papers in the case. Thank you for your kind assistance.

Sincerely,

Robert Watt

Robert M. Watt, III

rmw
encl.
cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/o encl.)
Dr. Carl Weaver (w/encl.)
Mr. Dick Galligan and Mr. Steve Estomin (w/encl.)
Mr. Robert J. Henkes (w/encl.)

SEELYE

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ADJUSTMENT OF RATES OF	)	CASE NO. 99-176
DELTA NATURAL GAS COMPANY, INC.	)	

REBUTTAL TESTIMONY OF

WILLIAM STEVEN SEELYE

AFFIDAVIT

The affiant, William Steven Seelye, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 99-176, in the Matter of: Adjustment of Gas Service Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached rebuttal testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at any hearing in Case No. 99-176 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his rebuttal testimony in such case.

William Steven Seelye

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by William Steven Seelye, this the 20 day of, October 1999.

Angela D. Wilson
Notary Public, State at Large, KY
My Commission Expires: My Commission Expires July 28, 2001

Angela W. Wilson
Notary Public, State at Large, Kentucky

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6711 Fallen Leaf, Louisville, Kentucky, 40241.

Q. ARE YOU THE SAME WILLIAM STEVE SEELYE THAT SUBMITTED TESTIMONY ON BEHALF OF DELTA NATURAL GAS COMPANY, INC. WHICH WAS FILED WITH THE COMMISSION ON JULY 2, 1999, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address (1) the direct testimony filed with the Kentucky Public Service Commission ("Commission") in September 1999 by Steven L. Estomin, Richard A. Galligan, and Robert J. Henkes with regard to general adjustments to Delta's rates and (2) the direct testimony filed in July, 1999 by Thomas S. Catlin and Robert J. Henkes in regard to Delta's proposed Alternative Regulation Plan ("Alt Reg Plan"). My rebuttal testimony will deal with the following subjects:

B. **<u>Cost of Service Issues</u>**. Rebuttal of Dr. Estomin's analysis of Delta's zero intercept analysis and Mr. Galligan's cost of service recommendations.

C. **<u>Pro-Forma Adjustments</u>**. Rebuttal of Mr. Henke's proposed adjustments to Year End Customer Expenses, Rate Case Expenses, and Bad Debt Expenses.

D. **<u>Alternative Regulation Plan</u>**. Rebuttal of comments made by Mr. Catlin and Mr. Henkes concerning Delta's alternative regulation plan.

II. COST OF SERVICE ISSUES

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STEVEN L. ESTOMIN, PH.D. IN THIS PROCEEDING?

A. Yes I have.

Q. DR. ESTOMIN CLAIMS THAT IN APPLYING THE ZERO INTERCEPT METHODOLOGY IN THE COST OF SERVICE STUDY YOU HAVE USED AN INCORRECT FORMULATION OF WEIGHTED LEAST SQUARES. IS DR. ESTOMIN CORRECT?

A. No he is not. Dr. Estomin has made some serious mathematical errors and has applied an incorrect formulation of weighted least squares. Consequently, Dr. Estomin's model produces incorrect results.

Q. CAN YOU DEMONSTRATE THIS?

A. Yes I can. In order to show that Dr. Estomin's weighted least squares model produces incorrect results, let's consider a sample set of data with a known slope and intercept so that we can compare the zero intercept obtained from Dr. Estomin's methodology to a known intercept. We can also compare the results obtained from the model that I utilize in order to determine which model produces the correct result. As will be demonstrated, Dr. Estomin's weighted least squares approach produces an incorrect result, while the weighted least squares approach that I utilize matches the actual intercept of the data perfectly.

The reason that weighted least squares must be used in determining the zero intercept is that in our cost of service study we are dealing with *average* unit costs of

II. COST OF SERVICE ISSUES

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF STEVEN L. ESTOMIN, PH.D. IN THIS PROCEEDING?

A. Yes I have.

Q. DR. ESTOMIN CLAIMS THAT IN APPLYING THE ZERO INTERCEPT METHODOLOGY IN THE COST OF SERVICE STUDY YOU HAVE USED AN INCORRECT FORMULATION OF WEIGHTED LEAST SQUARES. IS DR. ESTOMIN CORRECT?

A. No he is not. Dr. Estomin has made some serious mathematical errors and has applied an incorrect formulation of weighted least squares. Consequently, Dr. Estomin's model produces incorrect results.

Q. CAN YOU DEMONSTRATE THIS?

A. Yes I can. In order to show that Dr. Estomin's weighted least squares model produces incorrect results, let's consider a sample set of data with a known slope and intercept so that we can compare the zero intercept obtained from Dr. Estomin's methodology to a known intercept. We can also compare the results obtained from the model that I utilize in order to determine which model produces the correct result. As will be demonstrated, Dr. Estomin's weighted least squares approach produces an incorrect result, while the weighted least squares approach that I utilize matches the actual intercept of the data perfectly.

The reason that weighted least squares must be used in determining the zero intercept is that in our cost of service study we are dealing with _average_ unit costs of various sizes of pipe rather than the cost of each and every foot of pipe on the system. Since we do not have the cost of each and every foot of pipe on the system, the *average* unit cost for each size of pipe on Delta's system is the only data available for calculating the zero intercept . Therefore, it is important that the methodology selected for calculating the zero intercept is designed to deal with average unit cost data.

In order to show that the weighted least squares methodology that Dr. Estomin proposes is incorrect, let's look at a hypothetical gas system that has only 20 feet of pipe (instead of 6,478,911 feet in the case of Delta). With a hypothetical system that consists of only 20 feet of pipe where the installed cost of each segment of pipe is known, we can calculate the zero intercept directly.

Assume that the 20-foot system has five different sizes of pipe: 1.5" pipe, 2" pipe, 3" pipe, 4" pipe, and 6" pipe. The following table shows the cost of each foot of pipe on the system and the year the pipe was installed:

Pipe Size	Number of Feet	Unit Cost	Date Installed
1.5"	1	$4.00	1990
	1	$4.00	1991
2"	1	$4.75	1990
	1	$5.50	1991
	1	$5.75	1992
	1	$6.25	1993
	1	$6.50	1994
	1	$7.25	1997

Pipe Size	Number of Feet	Unit Cost	Date Installed
3.0"	1	$2.50	1975
	1	$1.50	1978
	1	$2.00	1979
	1	$2.00	1980
4.0"	1	$9.00	1998
6.0"	1	$4.00	1989
	1	$4.50	1992
	1	$8.00	1993
	1	$8.25	1994
	1	$8.45	1995
	1	$9.20	1997
	1	$13.60	1998

With this level of detail (i.e., with the cost of each foot of pipe on the system), there is no need to perform a weighted least squares regression in order to obtain the zero intercept. All we have to do is perform an ordinary least squares regression on each data point (i.e., each foot of main on the system), as follows:

x	y
1.5	4.00
1.5	4.00
2.0	4.75
2.0	5.50
2.0	5.75

x	y
2.0	6.25
2.0	6.50
2.0	7.25
3.0	2.50
3.0	1.50
3.0	2.00
3.0	2.00
4.0	9.00
6.0	4.00
6.0	4.50
6.0	8.00
6.0	8.25
6.0	8.45
6.0	9.20
6.0	13.60

Applying ordinary least squares (See SEELYE REBUTTAL EXHIBIT 1) to this complete set of data produces the following intercept and slope:

COMPARISON TABLE 1 Actual Zero Intercept and Slope of the System Applying Ordinary Least Squares to Each Data Point	
Zero Intercept	2.92392
Slope	0.80167

Now that we have the *actual* zero intercept and slope of the system, derived by applying ordinary least squares regression to the *actual*, raw cost data, we can compare these results to the case where ordinary least squares is applied to *average* unit cost data for each pipe size. In other words we will apply ordinary least squares regression to the *average* unit cost data in the following table.

Pipe Size	Number of Feet	Average Unit Cost
1.5"	2	$4.00
2.0"	6	$6.00
3.0"	4	$2.00
4.0"	1	$9.00
6.0"	7	$8.00

When standard weighted least squares is applied to the average unit cost data (see SEELYE REBUTTAL EXHIBIT 1) the following zero intercept and slope is obtained:

COMPARISON TABLE 2 ORDINARY LEAST SQUARES Applying Ordinary Least Squares to to Average Unit Cost Data	
Zero Intercept	2.62891
Slope	0.96094

As can be seen, applying ordinary least squares to ***average unit cost*** data does not produce the correct result. If the results of applying ordinary least squares to average unit cost data shown in COMPARISON TABLE 2 are compared to the actual zero intercept and slope shown in COMPARISON TABLE 1, we can see that his methodology does not produce the same results as applying ordinary least squares regression to the actual, raw data. This clearly shows that there is a major difference between applying ordinary least squares to *average* unit cost data and applying ordinary least squares to the *actual*, raw cost data. It is the application of ordinary least squares to the actual, raw data that produces a correct zero intercept. As I will show below, Dr. Estomin's incorrect weighted least squares model does not produce a correct zero intercept either. I will then show that only by applying standard weighted least squares to average unit cost data can we obtain the correct zero intercept derived by applying ordinary least squares regression to the actual, raw data.

Q. CAN YOU DEMONSTRATE WHICH METHODOLOGY PRODUCES THE CORRECT RESULT BY APPLYING BOTH DR. ESTOMIN'S METHODOLOGY AND YOUR METHODOLOGY TO THIS DATA SET FOR WHICH THE ZERO INTERCEPT IS KNOWN IN ADVANCE?

A. Yes we can. Only the properly formulated model will produce a zero intercept and slope that will match the actual results determined by applying ordinary least squares to each and every foot of pipe on the system.

Q. WHAT ZERO INTERCEPT AND SLOPE IS PRODUCED BY APPLYING DR. ESTOMIN'S MODEL?

A. Based on the testimony that he submitted in this proceeding, Dr. Estomin would optimize the following non-standard weighted least squares function:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

Using this non-standard weighted least squares function Dr. Estomin would then perform a least squares against the following equation:

$$n_i y_i = a n_i + b n_i x_i$$

where:

n_i is the number of feet for each size pipe

y_i is the average unit cost of each size pipe

x_i is the pipe size

a is the zero intercept

b is the slope

In other words, Dr. Estomin uses the number of feet of each size of pipe as weighting factors in applying the least squares regression, which is a non-standard formulation of the model. With Dr. Estomin's approach each data point would be weighted by n_i; therefore, he would apply a least squares regression to the following data:

$n_i y_i$	n_i	$n_i x_i$
8.0	2	3.0
36.0	6	12.0
8.0	4	12.0
9.0	1	4.0
56.0	7	42.0

When Dr. Estomin's weighting methodology is applied to the assumed sample of average unit cost data (see SEELYE REBUTTAL EXHIBIT 2) the following zero intercept and slope is obtained:

COMPARISON TABLE 3 Estomin Methodology Applying the Estomin Model to to Average Unit Cost Data	
Zero Intercept	3.33395
Slope	0.73491

Q. DOES DR. ESTOMIN'S METHODOLOGY PRODUCE THE SAME ZERO INTERCEPT AND SLOPE AS THE ACTUAL KNOWN RESULTS?

A. No it does not. If the results of Dr. Estomin's methodology shown in COMPARISON TABLE 3 are compared to the actual zero intercept and slope shown in COMPARISON TABLE 1, we can see that his methodology does not produce the correct results. His methodology results in a zero intercept that is significantly higher than the actual zero intercept.

Q. WHAT INTERCEPT AND SLOPE DO YOU GET WHEN YOU APPLY YOUR WEIGHTED LEAST SQUARES METHODOLOGY?

A. The methodology that I utilize is the standard approach for performing weighted least squares. It is the standard default methodology incorporated in the commercially available statistical software packages SPSS and SAS. This methodology optimizes the following weighted least squares function:

$$\sum w_i \ (Y_i - (a + bX_i))^2$$

Optimizing this function is equivalent to performing least squares against the following linear equation:

$$\sqrt{n_i}\, y_i = a\sqrt{n_i} + b\sqrt{n_i}\, x_i$$

again, where:

n_i is the number of feet for each size pipe

y_i is the average unit cost of each size pipe

x_i is the pipe size

a is the zero intercept

b is the slope

Using this standard weighted least squares approach, we would apply a least squares regression to the following data:

n^0.5y_i	n_i^0.5	n_i^0.5x_i
5.65685	1.41421	2.12132
14.69693	2.44949	4.89898
4.00000	2.00000	6.00000
9.00000	1.00000	4.00000
21.16601	2.64575	15.87451

When standard weighted least squares is applied to the average unit cost data (see SEELYE REBUTTAL EXHIBIT 2) the following zero intercept and slope is obtained:

COMPARISON TABLE 4 **STANDARD WEIGHTED LEAST SQUARES** **Applying the Seelye Model to** **to Average Unit Cost Data**	
Zero Intercept	2.92392
Slope	0.80167

Q. DOES THE STANDARD LEAST SQUARES APPROACH THAT YOU USE PRODUCE THE SAME ZERO INTERCEPT AND SLOPE AS THE ACTUAL KNOWN RESULTS?

A. Yes it does. When the results of standard least squares methodology shown in COMPARISON TABLE 4 are compared to the actual zero intercept and slope shown in COMPARISON TABLE 1, we can see that my approach produces ***exactly*** the same zero intercept and slope as the actual known results. This illustrates quite clearly that the model that I use is the correct formulation of weighted least squares for calculating the zero intercept based average unit cost data.

Q. DR. ESTOMIN SAYS IN HIS TESTIMONY THAT HIS WEIGHTED LEAST SQUARES METHODOLOGY PRODUCES APPROXIMATELY THE SAME RESULTS AS APPLYING ORDINARY LEAST SQUARES TO DELTA'S AVERAGE UNIT COST DATA. DO YOU AGREE?

A. As I demonstrated earlier, ordinary least squares regression applied to average unit cost data does not produce the same result as ordinary least squares regression applied to the actual cost data. It is ordinary least squares regression applied to the actual cost data that is of interest in determining the zero intercept. Thus, Dr. Estomin is using the wrong criteria to compare his results.

In general, his weighted least squares data will not produce the same results as applying ordinary least squares to average unit cost data. It is not appropriate to apply either Dr. Estomin's weighted least squares model or ordinary least squares to ***average unit cost data***. Because a different number of feet were utilized to calculate the averages, ordinary least squares will produce an incorrect result. If we apply ordinary least squares to the average unit cost data from our 20-foot system, we do not obtain the actual known slope nor does it produce a zero intercept or slope that approximates the results of Dr. Estomin's weighted least squares model.

Q. HAVE YOU PREPARED A TABLE THAT SUMMARIZES THE RESULTS OF APPLYING EACH METHODOLOGY?

A. Yes. The following table shows the zero intercept and slope calculated by each methodology:

Summary of Least Squares Methodologies

	Actual Results (Ordinary Least Squares Applied to Actual, Raw Data)	Ordinary Least Squares Applied to Average Unit Costs	Estomin Weighted Least Squares Model	Standard WeightedLeast Squares (Seelye Model)
Zero Intercept	2.92392	2.62891	3.33395	2.92392
Slope	0.80167	0.96094	0.73491	0.80167

As can be seen from this table, Dr. Estomin's model does not produce correct results. Likewise, applying ordinary least squares to average unit cost data does not produce correct results either. Neither Dr. Estomin's weighted least squares model nor ordinary least squares applied to average unit cost data produce a correct zero intercept in this situation. Only by using the model utilized in Delta's cost of service study can we obtain the correct zero intercept.

Q. ON PAGE 5 OF HIS TESTIMONY, DR. ESTOMIN STATES THAT "THE SQUARE ROOT OF A DATA SERIES SUCH AS THE NUMBER OF FEET OF MAINS IS OFTEN USED WHEN WEIGHTED SQUARES IS RELIED UPON TO CORRECT FOR HETEROSCEDASTICITY." DO YOU AGREE WITH THIS STATEMENT?

A. Yes I do. Dr. Estomin's observation is correct. However, he fails to explain that whenever we are performing a regression against *average data*, heteroscedasticity is inherently present in the formulation of the model. Heteroscedasticity is present when the variance of the error term e_α (and the variance of the independent variable z_α) is not constant. The error term and independent variable is said to be "heteroscedastic" if the variance is not constant. The error term and independent variable is said to be "homoscedastic"[1] if the variance is constant; in mathematic terms:

$$Var(e_\alpha) = Var(z_\alpha) = \sigma$$

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[1] Whenever ordinary least squares is applied, the assumption is made that the underlying data is homoscedastic. Therefore, when ordinary least squares is applied to individual data points (rather than averages) we are assuming that the data is homoscedastic. However, when the data has been averaged, the assumption can no longer be made that averages of homoscedastic data are homoscedastic. In fact averaging creates heteroscedasticity, as will be discussed below.

If we are taking averages of homoscedastic independent variables (as we have done with average unit cost of mains on Delta's system), then these averages become heteroscedastic. In other words, when y_i is the mean $\sum z_\alpha/n_i$ of a homoscedastic variable $z_1,\ldots,z_n$, then the variance of y_i is proportionate to n_i, which means that y_i is heteroscedastic. (See Ashish Sen and Muni Srivastava, *Regression Analysis: Theory, Methods, and Applications*, Springer-Verlag, 1990, Page 111.)

This means that when we are working with average data, with different values of n, as in the case of our average unit costs for various sizes of pipe, the average data is inherently heteroscedastic and therefore it is necessary to use weighted least squares to determine the zero intercept. By utilizing weighted regression, the correct estimate of the zero intercept can be obtained as though ordinary least squares regression were applied to the original raw data. When only average unit cost data is available, it is essential to apply standard weighted least squares in calculating the zero intercept. Neither ordinary least squares applied to average unit cost data nor Dr. Estominin's incorrect formulation of the weighted least squares model will produce correct results.

Q. HAS YOUR METHODOLOGY BEEN USED IN COST OF SERVICE STUDIES FILED WITH THE COMMISSION?

A. Yes, on many occasions. This methodology was used in electric and gas cost of service studies filed with the Commission in LG&E Case Nos. 90-158, 10064 and 8924 and the methodology was examined extensively in each of these cases. Dr. Estomin, on the other hand, states that he is unaware of any instance where his non-standard weighted least squares methodology has been adopted by this[2] or any other Commission.[3] Dr. Estomin is unaware of any instance where his methodology has ever been used in a cost of service study.[4] Furthermore, prior to this proceeding, Dr. Estomin has never performed a zero intercept analysis as a part of a professional study.[5]

Q. IS YOUR METHODOLOGY A STANDARD APPROACH SUPPORTED IN STATISTICAL LITERATURE?

A. Yes it is. The following discussion of weighted least squares is from Douglas C. Montgomery and Elizabeth A. Peck, *Introduction to Linear Regression Analysis*, Second Edition, Wiley Series in Probability and Mathematical Statistics, 1992, page 108:

> Linear regression models with nonconstant error variance can also be fitted by the method of *weighted least squares*. In this method of estimation the deviation between the observed and expected values of y_i is multiplied by a weight w_i chosen inversely proportionate to the variance of y_i. The weighted least squares function is
>
> $$S(\beta_0, \beta_1) = \sum_{i=1}^{n} w_i (y_i - b_0 - b_1 x_i)^2$$
>
> . . .
>
> To use weighted least squares, the weights w_i must be known. ***In some problems, the weights may be easily determined. For example, if the observation y_i is actually an average of n_i***

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[2] See the Attorney General's response to item 71 of Delta's data request dated October 4, 1998.

[3] *Ibid.* item 73.

[4] *Ibid.* item 72.

[5] *Ibid.* item 68.

observations at x_i and if all original observations have constant variance σ^2, then the variance y_i is $V(y_i)=V(e_i)=\sigma^2/n_i$, and we would choose the weights as $w_i = n_i$. (Emphasis supplied.)

This excerpt, which is from a standard textbook on regression, describes precisely the weighted least squares methodology that was used to calculate the zero intercept in Delta's cost of service study and describes precisely the underlying situation where the data actually consists of observations y_i (i.e., unit costs) that are in fact averages of n_i observations (i.e., averages of different feet of pipe for each size of main).

Q. IS THIS THE SAME APPROACH ADVOCATED BY DR. ESTOMIN?

A. No it is not. As can be seen on page 5, line 6 of his testimony, Dr. Estomin uses an incorrect formulation that includes a w^2 term in the weighted least squares function, as follows:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

Dr. Estomin's equation should be compared to the equation included in the quotation from Montgomery and Peck, *Introduction to Linear Regression Analysis*, shown above. Dr. Estomin's use of w^2 rather than w as the weighting factor results in a formulation of the model that is non-standard,[6] that is not automatically used in the statistical packages

[6] The only instance where Dr. Estomin's model would work with average data is under the virtually impossible situation where the underlying actual data (not the average data, but the underlying data from which the averages are calculated) exhibits a strange pattern of heteroscedasticity where the variances of the underlying data is proportionate to n_i. As mentioned earlier, whenever least squares is applied, the assumption is made that the data is homoscedastic. For Dr. Estomin's model to work, the variances of the underlying data would have to be proportionate to n_i, which would then produce average data that is proportionate to n_i^2. I have never seen this assumption made in analyzing real-world data. In fact, I have never seen

SAS and SPSS, that is not supported by statistical literature, and most importantly does not produce correct zero intercept, as we have shown earlier.

Q. IN HIS RESPONSE TO ITEM 66 OF DELTA'S DATA REQUEST, DR. ESTOMIN INDICATED THAT EVIEWS3, A PRODUCT OF QUANTITATIVE MICRO SOFTWARE, USES W_i^2 IN THE MINIMIZATION FUNCTION. CAN YOU EXPLAIN THIS?

A. Yes. In the EView3 model, when average data is being analyzed with weighted least squares, it is not appropriate to set w_i equal to the number of items being averaged n_i (e.g., feet of mains). To confirm this I called Quantitative Micro Software, Inc., the company that licenses EVIEWS3, and was connected to a technical support statistician. When I explained the fact that we were trying to apply weighted least squares regression to average data, the statistician said "when average data is being utilized, the variance of the data is proportionate to n_i; therefore, the w_i term must be set to the root of n_i [i.e. $\sqrt{n_i}$]." He said that the weighted least squares procedure described in the EViews3 User's Manual could be used with _average_ data but "be sure to set the weight variable equal to the root of the number of items for which the average is being calculated." This explanation is perfectly consistent with the standard weighted least squares methodology described in Montgomery and Peck, *Introduction to Linear Regression Analysis*, and in Ashish Sen and Muni Srivastava, *Regression Analysis: Theory, Methods, and*

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this assumption made at all. In addition, by using the weights he proposes, he would still be making the assumption that the average unit cost data is heteroscedastic (i.e., the variance is proportionate to n_i^2) which is inconsistent with his testimony.

Applications, cited earlier. It is also consistent with the methodology utilized in SPSS and SAS, and it is consistent with the methodology utilized in Delta's cost of service study.

Q. IF HIS APPROACH IS INCORRECT, WHY DO YOU BELIEVE THAT DR. ESTOMIN CAME UP WITH THIS NON-STANDARD FORMULATION?

A. It appears that Dr. Estomin developed this approach to try and convince the Commission to allocate a smaller percentage of cost on the basis of number of customers, thus reducing the percentage of cost allocated to the residential customer class. He is undoubtedly aware that the Commission has endorsed the zero intercept methodology in previous rate orders. (See for example the Commission's Orders in Case Nos. 90-158, 10064, and 8924.) The strategy of Dr. Estomin's client seems to be to shift a larger portion of the fixed costs from low volume users to high volume users.

Neither Delta nor I have a bias for or against any particular customer class in preparing the cost of service study. Normally we find ourselves between two extreme positions – i.e., between positions held by the large users and positions held by low-volume user groups, who both want as small a proportion of the costs allocated to them as possible. Normally, on cost of service issues, the Attorney General and other groups representing low volume consumers are busy arguing against positions held by the large users, and we usually find ourselves bracketed by two extreme positions. However, no commercial or industrial users have intervened in this case. It seems as though, since the Attorney General is the only intervenor in the case, that arguments favoring the low volume consumers are the only alternatives being presented.

Q. DR. ESTOMIN SEEMS TO SUGGEST THAT YOU SELECTED WEIGHTED LEAST SQUARES RATHER THAN ORDINARY LEAST SQUARES BECAUSE IT PRODUCES A LARGER ZERO INTERCEPT. WAS THIS THE REASON YOU SELECTED WEIGHTED LEAST SQUARES?

A. Absolutely not. As I have discussed the methodology that we utilize in calculating the zero intercept is the standard approach in performing linear regression against average data where the averages are computed using different numbers of items n_i. In this particular case we did not compare the zero intercept obtained by weighted least squares to the zero intercept obtained by applying ordinary least squares to average unit cost data. However, when I've done so in the past, there have been instances where weighted least squares resulted in a lower zero intercept. While at LG&E, I frequently used ordinary least squares to demonstrate to new employees the difference between the two methodologies and to illustrate how applying ordinary least squares to average unit cost data produces incorrect results. At LG&E, weighted least squares produced a lower zero intercept for gas mains, overhead electric conductor, underground electric conductor, and electric transformers.

Q. LET'S MOVE ON TO THE DIRECT TESTIMONY OF RICHARD A. GALLIGAN. HAVE YOU REVIEWED MR. GALLAGAN'S TESTIMONY?

A. Yes I have.

Q. DOES MR. GALLAGAN UTILIZE DR. ESTOMIN'S ZERO INTERCEPT ANALYSIS?

A. Oddly enough, no. After going to the trouble of bringing in a witness to present testimony on weighted least squares, Mr. Gallagan doesn't even use the zero intercept methodology. Instead of using the zero intercept methodology to determine the customer-related portion of the cost of mains, he arbitrarily assigned 50 percent of Delta's distribution mains costs as demand-related (i.e., allocated on the basis of peak demand) and 50 percent as commodity-related (i.e. allocated on the basis of annual usage). Under Mr. Gallagan's methodology, no mains costs are considered customer-related!

Q. IS 50% DEMAND/50% COMMODITY APPROACH CONSISTENT WITH PREVIOUS COMMISSION ORDERS DEALING WITH THE APPROPRIATE METHODOLOGY FOR CLASSIFYING DISTRIBUTION MAINS?

A. No it is not. The Commission has endorsed the use of the zero intercept methodology in the determination of the customer-related cost of mains investment in gas cost of service studies. In its Order in LG&E's Case No. 10064 the Commission stated as follows:

> *The Commission is convinced that the zero-intercept method is theoretically sound* and less subjective than the minimum system method, in which a minimum size main must be subjectively chosen in order to determine the customer component. (Case No. 10064, Order dated July 1, 1988, page 80. Emphasis supplied.)

The methodology used by the Mr. Galligan is very similar to the average and peak methodology, where the "average" portion of the cost is allocated on the basis of annual usage and the "excess" portion is allocated on the basis of "peak demand." In the past, the Commission has criticized the use of the "average and peak" methodology for allocating distribution mains. For example, in its Order in Delta's Case No. 97-066, the Commission stated as follows:

> The Commission is not convinced that the average and peak methodology has sufficient reliability to warrant it the Commission's complete reliance. Absent the use of another methodology to corroborate the average and peak methodology's results, *preferably the zero-intercept method*, this Commission will not give conclusive weight to studies using such methodology. (Case No. 97-066, Order dated December 8, 1997, page 24. Emphasis supplied.)

The methodology proposed by Mr. Galligan is also similar to a methodology that was rejected by the Commission in LG&E's Case No. 90-158. In that case, the Attorney General proposed to allocate one-third of distribution structures and equipment on the basis of class design-day demand and the remaining two-thirds on the basis of total class usage. Order, Case No. 90-158, dated December 21, 1990, pages 60 and 61

Q. DOES THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONER'S ("NARUC'S") GAS RATE DESIGN MANUAL, GAS DISTRIBUTION RATE DESIGN MANUAL, OR ELECTRIC UTILITY COST ALLOCATION MANUAL MENTION THE USE OF MR. GALLIGAN'S 50/50 METHODOLOGY WITH RESPECT TO ALLOCATING DISTRIBUTION COSTS SUCH AS THE COST OF MAINS?

A. No. There is no indication in these manuals that any portion of distribution costs should be allocated on the basis of commodity (i.e., annual gas usage). NARUC'S *Gas Rate Design Manual* states that "The Distribution Plant investment in mains ... consists of both demand and customer components." (NARUC, Gas Rate Design Manual, 1981, page 41.) NARUC's *Gas Distribution Rate Design Manual* states as follows:

> The distribution plant investment in mains may be classified as both demand and customer related. The customer component was determine[d] as the amount of investment that would be required i[f] all mains were comprised of a theoretically minimum size. (NARUC, *Gas Distribution Rate Design Manual*, 1989, page 32.)

Although NARUC's *Electric Utility Cost Allocation Manual* deals with electric cost of service studies, there are many analogical similarities between the distribution of electric energy and the distribution of natural gas. The manual states that poles, overhead conductors, underground conductors, line transformers and services "involve demand and customer costs." (NARUC, *Electric Utility Cost Allocation Manual*, 1992, page 90.) The manual goes on to describe the "minimum-size method" and the "zero intercept method." Mr. Galligan's methodology of allocating 50% as demand, 50% as <u>*commodity*</u>, and 0% as customer-related is not described.

Q. DOES IT MAKE INTUITIVE SENSE TO ALLOCATE A PORTION OF MAINS ON THE BASIS OF COMMODITY?

A. No. The cost of distribution mains does not relate to the amount of gas that flows through the pipe on an annual basis. The cost of distribution mains is affected by the number of customers on the system and the maximum gas demand placed on the system. It is intuitively obvious that when Delta makes a main extension to hook up a new customer, a certain amount of cost is incurred to hook the customer up irrespective of the customer's gas load. However, if the customer is expected to have a large peak demand, the cost of installing new mains will be comparatively higher than for a customer with a lower peak demand. This is the underlying rationale for classifying a portion of the mains cost as customer-related and classifying a portion as demand-related. When Delta hooks up a new customer, the cost of installing new gas mains to serve the customer is not affected by the customer's annual usage. Clearly, mains are installed to connect customers to the system and sized to meet the anticipated maximum demands imposed by the customers. Annual usage has no impact on the cost of installing mains, and none of the cost of mains should be classified as commodity related.

In trying to explain why he believes that distribution mains are not driven by the number of customers, he essentially admits that maximum demand, not annual gas volumes, drives the construction on mains:

> Mains costs are not incurred simply to connect customers and thus, dependent on the number of customers served from them, but for the loads placed upon them. This is made clear in the following example: Along one city block are located 10 Residential customers with a ***coincident peak demand*** of one MCF each. The main running down the street would have to be capable of delivering10 Mcf ***at peak***. On another city block is only a small plastics factory that exhibits a maximum demand of 10 Mcf. The main for that one customer has to be sized to deliver 10 Mcf ***when the plastics demand peaks***. It is clear that the ***mains investment is driven by the loads placed upon it*** – not by the number of customers served from it. (Direct Testimony of Richard A. Galligan, page 8. Emphasis supplied.)

We agree with Mr. Galligan that the utility's mains investment is affected by the loads (demand at peak) placed on it, not by the annual volume of gas sold. This example that Mr. Galligan offers completely contradicts the concept that he tries to develop later in his testimony (beginning on page 11) that the cost of distribution mains are incurred to meet annual volumes of gas. Distribution mains must have the capacity to meet peak demands; however, the size of the pipe is not affected by the amount of gas that flows through the pipe throughout the year. The cost of mains will be the same whether gas peak load flows through the pipe 100 percent of the time, 50 percent of the time or 25 percent of the time.

If Delta's annual throughput volumes happen to be higher because of colder than normal temperatures during the winter heating season, then Delta's investment in mains will not go up. Likewise, if Delta's annual throughput volumes happen to be lower because of milder than normal temperatures, then Delta's investment in mains will not go down. Delta's distribution mains are sized to meet maximum demands, not annual throughput volumes. It is for this reason that, in Delta's cost of service study, demand-related costs were allocated on the basis of maximum class demands based on a design day temperature. A methodology that allocates mains investment on the basis of annual gas volumes does not properly reflect cost causation on the system.

Q. BUT DO YOU AGREE THAT MR. GALLIGAN'S EXAMPLE SHOWS THAT THE NUMBER OF CUSTOMERS DO NOT AFFECT THE MAINS INVESTMENT?

A. No. In Mr. Galligan's example, the distribution system materializes fully formed out of thin air. In reality, the utility would hook up customers in accordance with its main extension policy. According to Delta's main extension policy, Delta will install up to 200 feet of main to hook up a new customer. Obviously, in some areas, the extension required would be less than 200 feet, thus bringing the average length of extensions down below 200 feet. But in accordance with its extension policy, Delta will install up to 200 feet of mains for a new customer. Therefore, for every customer that Delta hooks up, up to 200 feet of main must be installed, regardless of the load the customer places on the system. The customer may either occupy a large home or a small home and may use gas for space heating, water heating, cooking, clothes drying and artificial fireplace logs or may only use gas for water heating. Nevertheless, Delta must still install the main extension in accordance with its policy. If more than 200 feet of pipe is required, then the customer must make a cash advance for the excess cost of construction (which will eventually become a contribution in aid of construction if additional customers are not hooked up along the main extension.) Consequently, adding new customers directly impacts the cost of mains on the system (by up to 200 feet of mains on the system).

Q. DOES MR. GALLIGAN PROVIDE ANY BASIS FOR CLASSIFYING 50 PERCENT OF THE COST AS DEMAND RELATED AND 50 PERCENT AS COMMODITY RELATED?

A. No. The 50/50 split is completely arbitrary. He argues that a portion of the cost is related to annual throughput volume and then arbitrarily allocates 50 percent of Delta's distribution mains cost on that basis. This is hardly a scientific approach. Since he provides no basis or rationale for selecting a supportable percentage, Mr. Galligan could have just as arbitrarily chosen some other split, such as a 90/10 split or 75/25 split.

Q. DID YOU EXAMINE MR. GALLIGAN'S COST OF SERVICE STUDY?

A. Yes.

Q. SHOULD MR. GALLIGAN'S COST OF SERVICE STUDY BE USED FOR

RATEMAKING PURPOSES?

A. No. Mr. Galligan's cost of service study does not use a standard cost of service methodology. He arbitrarily classifies 50% of distribution and transmission mains as demand-related, 50% as commodity-related, and 0% as customer-related. This is not consistent with any methodology discussed in NARUC's *Gas Rate Design Manual*, *Gas Distribution Rate Design Manual*, or the *Electric Utility Cost Allocation Manual*; nor is his method of classifying costs consistent with any methodology approved by the Commission. In addition, his study is not well documented. As a part of his testimony, Mr. Galligan included a cost of service study consisting of one page. In response to item 83 of Delta's data request dated October 4, 1999, Mr. Galligan provided workpapers but failed to provide a detailed description of the functional assignment and allocation procedures used. Surprisingly, without considering the results of his own study, Mr. Galligan then simply proposes the same percentage increase to all customer classes.

Q. ON PAGES 24 AND 25 OF HIS TESTIMONY, MR. GALLIGAN QUESTIONS WHETHER THERE IS A DIFFERENCE BETWEEN FIRM AND INTERRUPTIBLE SERVICE. IS THERE A DIFFERENCE BETWEEN THESE SERVICES?

A. Yes, there is. The fact that Delta has not actually curtailed its interruptible customers for a number of years is irrelevant. Mr. Galligan suggests that interruptible service should not be priced at a lower rate since Delta has experienced design day weather conditions six times from 1989 to 1997 and did not interrupt these customers. However, Mr. Galligan fails to consider that more than peak day conditions determine whether a customer is interrupted. Delta utilizes a combination of gas delivered to the city gate and storage to meet peak day requirements. Since Delta relies on storage in addition to city gate capacity to meet peak demands, the amount of capacity available at any given time is determined by the amount (or deliverability) of gas available from storage as well as total city-gate capacity. Unlike city gate capacity, storage deliverability can be reduced (or impaired) due to extreme weather conditions over the course of the winter season. In other words, Delta must plan to meet peak day conditions as well as design winter conditions. An extremely cold winter could deplete Delta's storage to the point that if a design day temperature occurs late in the winter season, then it would be necessary to curtail its interruptible customers. This situation has not occurred during the past 10 years. During the past 10 years conditions have not necessitated the curtailment of interruptible service.

Q. BECAUSE DELTA HAS NOT CURTAILED ITS INTERRUPTIBLE CUSTOMERS FOR A NUMBER OF YEARS, DOES THIS MEAN THAT INTERRUPTIBLE CUSTOMERS SHOULD RECEIVE A FULL ALLOCATION OF STORAGE AND TRANSMISSION COSTS?

A. No. Even though these customers have not been interrupted for a number of years, it does not mean that they are receiving firm service. These customers are receiving interruptible service, and during an extreme winter it would be necessary to interrupt these customers. Interruptible customers are the first to be curtailed during emergencies. Therefore, interruptible service plays an important role in maintaining the operational integrity of the system. Consequently, interruptible service provides utilities greater operational flexibility during extreme winter conditions and provides an important buffer for maintaining the operational integrity of the system and for preserving the ability to serve essential human needs requirements. Without interruptible service, the utility would have to curtail firm customers during critical periods, purchase significantly more city gate capacity or develop more storage capacity. Mr. Galligan's suggestion that the lower rate for interruptible service be discontinued would be operationally dangerous and unsupported by the fact that Delta does not plan to provide service to these customers during extreme winter conditions.

Q. HOW WAS INTERRUPTIBLE SERVICE HANDLED IN DELTA'S COST OF SERVICE STUDY?

A. Interruptible customers received a full allocation of transmission and distribution costs. The only costs that were not allocated to interruptible customers were storage-related costs. The reason that storage-related costs were not allocated to interruptible customers is that Delta does not have to reserve either city-gate capacity from its transmission suppliers (Columbia Gas Transmission and Tennessee Gas Pipeline) or install storage capacity to meet peak day demands for interruptible customers. This is consistent with Mr. Glenn Jennings' discussion of the purpose of storage included in response to item 46 of the Attorney General's Supplemental Request for Information:

> The primary benefit derived from storage services is security of supply for Delta's ***firm customers*** . . . Storage service is essential to meet the needs of Delta's ***firm customers*** in the south systems. The total ***firm***, peak day load of these systems exceeds the capacities of the pipeline supplying gas to Delta for these systems. Without storage, Delta could not supply requirements of its ***firm customers***. (Emphasis supplied.)

Clearly, Delta plans its storage and purchased transmission capacity around meeting the requirements of its firm customers, not its interruptible customers. As mentioned earlier, the fact that Delta has not curtailed interruptible service for a number of years is irrelevant; what is important, in terms of cost of service, is whether storage capacity has been installed to meet the winter season requirements of interruptible customers under extreme winter conditions. Without interruptible service Delta would have to either purchase more city gate capacity, if it is available, or install additional storage or a combination of both.

III. PRO-FORMA ADJUSTMENTS

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF ROBERT J. HENKES FILED SEPTEMBER 23, 1999?

A. Yes I have. This is the Mr. Henkes' testimony dealing with Delta's proposed general adjustment in rates.

Q. ON PAGE 22 OF HIS TESTIMONY, MR. HENKES DISCUSSES DELTA'S YEAR-END CUSTOMER EXPENSE ADJUSTMENT. HE RECOMMENDS LOWERING THE ADJUSTMENT TO REFLECT A LOWER EXPENSE-TO-REVENUE RATIO. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No I do not. Mr. Henkes argues that because wages and salaries were removed from the calculation of the expense-to-revenue ratio for the year end adjustment then a host of other expenses should also be removed from the calculation. He reasons that "[i]f the Company takes the position that the level of its current employees will not vary with the incremental sales for year end customers, then it would be consistent to also assume that pension and benefit expenses associated with these same current employees will not vary with the incremental sales for year end customers." He goes on to argue that other costs should also be subtracted because, in his opinion, these other costs do not vary with incremental sales.

In response to this argument, let me first say that it is not Delta's position that the number of employees do not vary with incremental sales. In fact, we feel that wages and salaries vary directly with the size of Delta's customer base. Over the years, Delta has added new employees in response to growth on the system, and will have to continue to add new employees in response to continued growth of the system. By way of illustration, let's assume that Delta were to double in size. Clearly, if Delta were to double the number of customers that it serves, then it would have to hire additional employees in order to provide service for the larger customer base. With twice the number of customers, Delta would have to install more facilities (e.g. mains, services, meters), which, of course, means that there would be more facilities to operate and maintain, more meters to read, and more bills to render. Obviously, Delta couldn't double in size without adding new employees. In general, Delta cannot grow without adding new employees.

This begs the question – then why did Delta calculate the expense-to-revenue ratio by subtracting wages and salaries? The answer is simply that we were following prior Commission practice. In following this practice, it should not be inferred that we believe that salaries and wages do not vary with incremental sales from year end customers. We would like to point out, respectfully, that in our opinion calculating the expense-to-revenue ratio by removing salaries and wages from total O&M expenses removes too much cost. There may possibly be some economies of scale associated with serving additional customers in the administrative areas, but this does not imply that *all* salaries and wages should be removed from the calculation of the expense-to-revenue ratio. In all due respect to past Commission decisions, we believe that the traditional practice of removing wages and salaries from the calculation of the expense-to-revenue ratio, understates the expenses associated with serving the additional number of customers represented by year-end over average customers.

Q. HAS MR. HENKES SHOWN THAT THE ADDITIONAL EXPENSES THAT HE REMOVED FROM THE CALCULATION OF THE EXPENSE-TO-REVENUE RATIO DO NOT VARY WITH INCREASED SALES TO YEAR END CUSTOMERS?

A. No he has not. His reasoning is based on the incorrect premise that it is Delta's position that wages and salaries should be removed because current employees will not vary with incremental sales for year end customers. Mr. Henkes has not shown that the expense-to-revenue ratio that he calculates reflects the appropriate level of incremental operating expenses. Without a detailed marginal cost analysis of Delta's operation and maintenance expenses, Mr. Henkes cannot support his proposed expense-to-revenue ratio. In other words, he offers no support that the level of incremental expenses that is reflected in his proposed expense-to-revenue ratio reflects the marginal operation and maintenance expenses associated with serving additional customers.

Q. IF THE COMMISSION MODIFIES THE CALCULATION OF THE EXPENSE-TO-

REVENUE RATIO, WHAT DO YOU RECOMMEND SHOULD BE DONE?

A. If the Commission modifies its longstanding practice of removing wages and salaries from the calculation of the expense-to-revenue ratio, then I would recommend that salaries and wages should not be removed from O&M expenses. Even though there may be some small economies of scales associated with serving additional customers, I believe that this approach would provide a more accurate estimate of the marginal O&M expenses of serving new customers than the methodology that has been traditionally utilized by the Commission.

Q. HAVE YOU RECALCULATED THE YEAR END CUSTOMER EXPENSE ADJUSTMENT BASED ON THIS RECOMMENDATION?

A. Yes I have. If salaries and wages are not removed from O&M expenses, the expense adjustment would be $197,978. The supporting calculations for this adjustment are shown in SEELYE REBUTTAL EXHIBIT 3.

Q. ON PAGES 27-29 OF HIS TESTIMONY, MR. HENKES RECOMMENDS REMOVING THE AMORTIZATION OF RATE CASE EXPENSES WHICH WERE APPROVED BY THE COMMISSION IN CASE NO. 97-066. DO YOU AGREE WITH MR. HENKES' ADJUSTMENT?

A. No I do not. It is Mr. Henkes' position that the Commission should not allow Delta to amortize its rate case expense, but, rather, should be guided by the principle of "normalization." There are several problems with Mr. Henkes' recommendation. *First*, Mr. Henkes confuses the concept of "amortization" with the concept of "normalization." *Normalization* is appropriate when costs vary from year to year due to randomly occurring effects on the utility's operations. For example, the Commission has traditionally required gas utilities to make a temperature normalization adjustment to reflect normal temperature. Because revenues vary from year to year due to temperature, the Commission has determined that it is appropriate to reflect, on a going forward basis, a level of revenue that corresponds to normal temperatures. *Amortization*, on the other hand, is used to deal with costs that do not occur every year, such as rate case expenses, extraordinary expenses, non-recurring costs, etc.

Second, Mr. Henkes' recommendation is in direct contravention of the Commission's Order in Case No. 97-066. The Commission's Order states as follows:

> Rate Case Expense. Delta estimated rate case expenses of $75,000. It proposed to amortize these expenses over a 3-year period and to increase test year expenses by $25,000. While accepting Delta's level of rate case expense, the ***AG urges that these costs should be recovered over a 5-year period*** to reflect the historical interval between Delta's rate application. Delta has incurred a total of $101,349.75 in rate case expenses. This total exceeds Delta's projected cost by approximately 33 percent. ***The Commission finds that these costs should be recovered over a 5-year period*** to reflect the interval between Delta's rate filings. Accordingly, the Commission has increased test year expenses by $20,270. (Case No. 97-066, Order dated December 8, 1997, page 13. Emphasis supplied)

Mr. Henkes' recommendation is not consistent with past Commission decisions and would be contrary to the Commission's Order in Case No. 97-066. In Case No. 97-066, the Commission accepted Delta's proposal to amortize rate case expenses. The Commission's Order says that rate cases expense should be " recovered over a 5-year period." The Order does not say that expenses should be adjusted to reflect "normalization" or a "normal level of rate case expenses." The Commission thus recognized that it is appropriate for Delta to amortize these expenses. Furthermore, the Commission indicated that Delta could *recover* these expenses over a 5-year period. At this time, Delta has not recovered these expenses. With Mr. Henkes recommendation, Delta would be prevented from ever recovering these expenses; thus his recommendation violates the Commission's Order in Delta's last rate case.

Third, Mr. Henkes' recommendation is inconsistent with his position in Case No. 97-066; in fact, he has completely reversed his position. In that proceeding, he argued that rate case expenses should be "amortized over a 5-year period." (See Case No. 97-066, Direct Testimony of Robert J. Henkes, page 36.) In his testimony, nothing was said of "normalizing" rate case expenses. Now that only two years has past since Delta's last rate case, instead of five years as he recommended, he would prefer to "normalize" rather than "amortize." This is a good example of Mr. Henkes doing a flip-flop on an issue as well as picking and choosing whatever methodology and supporting argument that produces the lower revenue requirements he is after.

Fourth, Mr. Henkes' recommendation runs counter to the Commission's practice of establishing revenue requirements on an "accrual basis" rather than on a "cash basis." The Commission has a longstanding practice of using an accrual basis for determining revenue requirements, even for non-profit entities. Under a cash approach, revenue requirements would be determined on the basis of a normalized level of expenditures, rather than on the basis of accruals. Allowing Delta to recover amortization of rate case expenses is no different than allowing Delta to recover depreciation accruals as a current expense. Under a "cash approach" for determining revenue requirements, an expected or normalized level of plant expenditures would be used to determine revenue requirements rather than depreciation accruals. Depreciation is simply a way of writing off costs in an orderly manner over a certain period of time. Amortization performs the same function – it is used to spread an extraordinary or one-time cash expenditure over a specified number of years. Mr. Henkes' recommendation is therefore tantamount to switching to a cash basis for this particular cost item. In other words, Mr. Henkes would have the Commission normalize rate case expenses to reflect an expected level of "cash" to be spent for conducting a rate case rather than establishing an "accrual."

Q. ON PAGES 30-31 OF HIS TESTIMONY, MR. HENKES PROPOSES AN ADJUSTMENT TO AVERAGE BAD DEBT EXPENSES OVER 4 YEARS. DO YOU AGREE WITH THIS ADJUSTMENT?

A. No I do not. Mr. Henkes is making a post test year adjustment by inconsistently identifying a single cost item for special treatment. Mr. Henkes picks out a single cost item that might possibly trend down because of efforts on the part of Delta's management and then projects a post test year decrease in the expense. There are many other expenses that are likely to increase after the end of the test year, but Mr. Henkes has not made an upward adjustment for these expenses.[7] Delta's expenses in general are likely to increase after the end of the test year and consistent with Mr. Henkes' treatment of bad debt

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[7] In his Rebuttal Testimony, Mr. John Brown discusses this point in greater detail and provides several examples of costs that are currently higher than they were during the test year ended December 31, 1998.

expenses, these other expenses should be adjusted upward. Delta has not proposed to look beyond the end of the test year for determining other operation and maintenance expenses; therefore, Mr. Henkes' post test year adjustment is inappropriate and should not be considered.

Additionally, bad debt expenses do not exhibit the type of variability that would generally warrant the use of cost of service averaging. As I mentioned earlier, the Commission has allowed normalization of expenses when costs exhibit variations due to random effects. I am unaware of the Commission using averaging, or other trending mechanisms, to account for a post test year event that might or might not occur when the rates go into effect. In the case of bad debt expenses, the data over the past few years indicates an upward trend. Looking at the historical data for the past four years, there is no basis to conclude that the level of bad debt expense proposed by Mr. Henkes represents a reasonable level on a going forward basis. In other words, Mr. Henkes has not shown that adjusting bad debt expenses based on a four year average represents a known and measurable adjustment to test year levels of expenses.

Mr. Henkes' adjustment to bad debt expenses should be rejected because (1) it reflects a post test year adjustment, (2) he does not consistently apply his post test year logic to other expenses that have either increased or are likely to increase when the rate go into effect, (3) he does not show that averaging produces a reasonable level of expenses on a going forward basis, and (4) his adjustment does not reflect a known and measurable change to test year operating results.

Q. DO YOU AGREE WITH MR. HENKE'S RECOMMENDATION TO TREAT

DELTA'S CUSTOMER DEPOSIT BALANCES AS A RATE BASE DEDUCTION?

A. No. This is yet another example of Mr. Henkes simply looking for creative ways to reduce Delta's revenue requirements. He argues that customer deposits are conceptually no different than customer advances. This is not correct. The major distinguishing factor which Mr. Henkes ignores is the *use* of the money. Customer advances ALWAYS relate to the construction of gas distribution facilities that have been installed on behalf of customers. As a result, customer advances are closely related to rate base. For example, as a part of Delta's main extension policy, residential customers must make a cash advance for extensions that exceed 200 feet. If other customers do not connect to the main within ten years, these advances are then credited as a contribution in aid of construction, which reduces plant in service. Therefore, customer advances relate directly to Delta's plant in service and, therefore, its rate base. Customer advances are deducted from rate base because Delta does not have to raise the capital for that amount of plant investment. Customer deposits, on the other hand, do not relate to plant in service nor to any other rate base item.

IV. DELTA'S ALTERNATIVE REGULATION PLAN

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF ROBERT J. HENKES AND THOMAS S. CATLIN FILED IN JULY 1999 IN REGARD TO DELTA'S PROPOSED EXPERIMENTAL ALT REG PLAN?

A. Yes.

Q. BEGINNING ON PAGE 9 OF HIS TESTIMONY, MR. HENKES ARGUES THAT

UNDER ITS PROPOSED EXPERIMENTAL ALT REG PLAN DELTA IS GUARANTEED TO EARN ITS AUTHORIZED RETURN ON EQUITY. IS MR. HENKES CORRECT?

A. No. Although the proposed Alt Reg Plan would provide greater assurance that Delta would earn a rate of return within the range authorized by the Commission, the proposed plan would not translate into a guaranteed rate of return as claimed by Mr. Henkes. In making this argument, Mr. Henkes seems to ignore the amendments that Delta made to its proposed alt reg plan to incorporate performance based cost control measures. With the performance based cost controls, the argument cannot be made that Delta will have any assurance whatsoever that it will earn a rate of return which will fall within the range authorized by the Commission. Even under its original filing, Delta would not have been given a guaranteed rate of return, but would have been allowed to operate within a range found to be fair, just and reasonable by the Commission. But with the performance base cost controls in place, if Delta does not meet the performance criteria then it will not necessarily earn a rate of return that will fall within the authorized range.

Q. WHY DIDN'T DELTA INCLUDE THESE PERFORMANCE BASED CONTROLS IN ITS ORIGINAL FILING?

A. We did not include these performance based controls in the original filing because we had expected that we could develop a set of mutually agreeable set of controls with the parties in the proceeding. In other words, we were hoping to generate a discussion or dialogue with the Attorney General and possibly other parties so that we could collaboratively develop a set of controls and other features of the mechanism that would be acceptable to all parties. Our inability to generate such a dialogue or discussion underscores a problem with traditional regulation. Under the traditional regulatory process, the parties often stake out their positions and each party continues to go down its individual path which makes it difficult to come to some middle ground. In saying this I do not want to give the impression that I feel that traditional regulation in Kentucky is not working. Clearly, traditional regulation has worked well in Kentucky – for evidence, just look at the low utility rates that are enjoyed in the state. But in spite of how well traditional regulation has worked in Kentucky, I believe there is room for improvement. For example, there is room for improvement when we have a gas utility trying to serve customers in rural Kentucky whose earnings have been so poor that it has only earned enough to pay its dividends in one out of the last five years. There is room for improvement when there is a small rural utility whose earnings are so poor that its equity percentage is now below 30 percent. There is room for improvement when there is currently such a large disparity between the earnings of gas utilities and the earnings of electric utilities in the state.

Q. BESIDES THE IMPACT OF THE PERFORMANCE BASED COST CONTROL MEASURES, ARE THERE OTHER ASPECTS OF DELTA'S PROPOSED ALT REG PLAN THAT MR. HENKES AND MR. CATLIN FAIL TO CONSIDER?

A. Yes. Both Mr. Henkes and Mr. Catlin fail to recognize that the proposed Alt Reg Plan protects customers from the utility charging rates that allow it to earn an excessive rate of return. Perhaps the reason that the Attorney General witnesses may not be too concerned with this benefit is that they believe that it is unlikely that Delta will earn an excessive rate of return. But this point of view is short sighted and lacks historical perspective.

One of the primary factors that cause a utility's rate of return to decline is the need to install additional facilities to meet customer growth. For electric utilities, once they installed enough generation capacity to meet expected demands, which for most of them was in the mid 1980s, they had less difficulty achieving or even exceeding their authorized rate of return. One of the principal reasons for this was that the level of capacity-related depreciation reflected in rates would often exceed capital expenditures for the additional facilities needed to serve new customers. Stated another way, the marginal cost of serving new electric customers is now less than the embedded cost reflected in rates. Therefore, over the past several years, in spite of significant customer growth, most electric utilities are now having much less trouble than they were in the 1970s and 1980s earning their authorized rates of return.

Gas utilities, on the other hand, have generally not fared as well over the past several years. A reason for this is that such a large percentage of a gas utility's capital expenditures is related to the installation of distribution facilities, which are directly affected by customer growth. In Delta's case, significant capital expenditures were also required to install transmission capacity necessary to provide reliable gas service to rural customers in the southern part of its service territory. However, if the marginal cost of serving a new rural gas customer ever becomes less than the embedded cost per customer reflected in rates, then a significant downward force on Delta's earnings would be eliminated and its earned rate of return would likely begin to go up rather than continually going down. If this were to occur, then the proposed Alt Reg Plan would help prevent Delta's earned rate of return from exceeding the upper end of the range authorized by the Commission. This is a very important customer benefit that the Attorney General witnesses have failed to recognize. Throughout their testimony, Mr. Henkes and Mr. Catlin fail to acknowledge the protection that the proposed Alt Reg Plan would provide customers in preventing the utility from earning too high of a rate of return. The benefits are not as one sided as they would have us believe. They focus their attention on the protection that the Alt Reg Plan would provide Delta on the low end of the rate of return range, but they ignore the protection that the mechanism would provide customers on the high end of the range.

Q. ARE THERE ANY OTHER ISSUES THAT THE ATTORNEY GENERAL WITNESSES FAIL TO CONSIDER.

A. Yes. The Attorney General witnesses fail to recognize that the Alt Reg Plan is fully consistent with the Commission's statutory mandate for ensuring that the "utility may demand, collect and receive fair, just and reasonable rates for the service rendered" as required by KRS 278.030. If the relationship between a utility's marginal cost and the embedded cost reflected in rates causes the utility to earn an inadequate rate of return, then the utility is not being allowed to "demand, collect and receive fair, just and reasonable rates." Likewise, if the relationship between marginal costs and embedded costs reflected in rates causes the utility to overearn, then it can hardly be argued that the utility's rates are fair, just and reasonable. By providing greater assurance that the utility will neither over-earn nor under-earn, Delta's proposed Alt Reg Plan is more consistent with KRS 278.030. The Attorney General's failure to recognize this point is significant.

Q. BUT WOULD DELTA'S PROPOSAL ALLOW IT TO INCREASE COSTS WITHOUT

CONSTRAINT, AS SUGGESTED BY THE ATTORNEY GEENERAL WITNESSES?

A. Not at all. First, Delta cannot afford to ignore increases in its costs without significantly impairing its ability to compete with other energy service providers. Delta already realizes significant competitive pressures from electric utilities, propane suppliers and from coal suppliers. This is illustrated in SEELYE REBUTTAL EXHIBIT 4 which shows the estimated price relationships of different energy services for residential customers in Delta's service area. Second, the performance based cost controls proposed by Delta would penalize Delta for increasing costs above 101.5% of the Indexed O&M Expenses determined on the basis of changes in CPI-U.

Q. BOTH MR. HENKES AND MR. CATLIN ARGUE THAT INDEXING AGAINST CPI-U DOES NOT PROVIDE AN INCENTIVE FOR DELTA TO IMPROVE ITS PERFORMANCE OVER HISTORICAL LEVELS. DO YOU AGREE WITH THEM?

A. No. The Attorney General witnesses argue that since Delta's non-gas operation and maintenance expenses have outperformed CPI-U for the past 5 years, Delta has no incentive to improve performance over historical levels. Their argument is incorrect. First, Mr. Henkes and Mr. Catlin are assuming that the historical performance during the past five years is somehow indicative of future performance. The performance for the last 5 years will not impact the O&M calculations in any way for future application under the proposed Alt Reg Plan. Second, Mr. Henkes and Mr. Catlin fail to consider that the mechanism provides an incentive for Delta to retain 50 percent of the O&M savings if Delta outperforms CPI-U less the 1.50% deadband. Therefore, no matter how well Delta outperforms the index, there is always an incentive for Delta to improve its performance even more. The Attorney General witnesses have plainly missed this point, even though it is the same share-of-the-savings concept that has been used in the performance-based ratemaking mechanisms approved for Columbia Gas of Kentucky, Western Kentucky Gas Company, and Louisville Gas and Electric Company.[8]

In order to illustrate how Delta has an incentive to improve performance over historical levels, suppose that the Index O&M Expenses for a year are $9,500,000. Now, suppose that Delta's actual O&M expenses for the year, are $9,357,500, which is 98.5% of the index. In this example, there would not be any savings to share because Delta's O&M are not less than 98.5% of the Indexed O&M expenses. Now suppose that Delta takes specific managerial actions designed to reduce its O&M expenses and through those efforts is able to reduce its expenses by $500,000 which brings its total O&M expenses down to $8,857,500. Delta would then be able to retain 50% of these savings (50% x $500,000 = $250,000) and the customers would receive the other 50% of the savings. Therefore, both Delta and its customers would benefit from Delta's efforts to reduce costs. No matter how low Delta can decrease its costs there would always be an incentive to reduce costs further.

Another major flaw in their analysis is that they compare Delta's non-gas O&M expenses to a CPI-adjusted index calculated over a 5-year period rather than recognizing that the Indexed O&M Expense is redetermined every 3 years as proposed in the Alt Reg

[8] See the Commission's Orders in Columbia Gas of Kentucky, Inc., Case No. 96-079, dated July 31, 1996; Louisville Gas and Electric Company, Case No. 96-171, dated September 30, 1997; and Western Kentucky Gas Company, Case No. 97-513, dated June 1, 1998.

Plan. On pages 35 and 36 of his testimony, Mr. Henkes compares Delta's actual O&M expenses to the recoverable expenses based on the Indexed O&M Expense Cost Control Benchmark for a 5-year period from 1994 through 1998. Mr. Catlin performs a similar 5-year analysis on page 10 of his testimony (lines 14-17). However, under Delta's proposed Alt Reg Plan the O&M expenses reflected in base rates would be re-established every 3 years. Comparing Delta's O&M expenses to a 5-year index is both meaningless and misleading. By looking at 5 years without re-establishing the O&M Expense Index every 3 years the Attorney General witnesses have significantly overstated the amount that Delta's O&M expenses that would have exceeded the Indexed O&M Expense Cost Control Benchmark during the period.

Q. SEVERAL TIMES THROUGHOUT HIS TESTIMONY MR. HENKES CLAIMS THAT DELTA'S PERFORMANCE BASED COST CONTROLS DO NOT REPRESENT A "CHALLENGING", "HARD TO ACHIEVE" OR "TOUGH" BENCHMARK. DOES DELTA'S PERFORMANCE BASED CONTROL NEED TO BE TOUGH IN ORDER TO PROVIDE AN INCENTIVE?

A. No. But before explaining this, let me say that Mr. Henkes provides no objective measurement of what he means by the terms "challenging", "hard to achieve" and "tough". He claims that in their PBR mechanisms, Columbia Gas, Western Kentucky Gas and LG&E proposed "hard-to-achieve" or "tough" benchmarks. However, there is no indication that Mr. Henkes even looked at the actual periodic PBR filings of these companies.[9] His familiarity with and understanding of these other mechanisms appear to be cursory at best.[10] He did not evaluate how well the gas supply costs have performed in relation to the benchmarks utilized by these companies.[11] Therefore, Mr. Henkes provides no evidence that the benchmarks utilized in the PBRs of Columbia Gas, Western Kentucky Gas and LG&E are any more "challenging", "hard to achieve" or "tough" than Delta's proposed cost benchmark.

However, it is not important whether Delta or these other companies have established a "challenging", "hard to achieve" or "tough" benchmark. The criteria that should be used to evaluate the performance based controls are (1) whether the benchmark selected is reasonable, and (2) whether the mechanism provides an incentive for the utility to improve performance. CPI-U is a commonly used cost index and is the index used in Alabama Gas Company's mechanism. And as I have explained earlier, the share-of-the-savings mechanism incorporated in Delta's Alt Reg Plan provides a powerful incentive for Delta to improve its operational performance, regardless of whether Delta's O&M expenses are above or below the Indexed O&M expenses. Therefore, Delta's Alt Reg Plan meets both of these criteria.

Q. ON PAGE 31 OF HIS TESTIMONY, MR. HENKES ARGUES THAT THE USE OF BUDGETED INFORMATION IN THE CALCULATION OF THE ANNUAL ACTUAL

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[9] See the Attorney General's response to item 47(a) and 47(g) of Delta's data request dated October 4, 1999.

[10] *Ibid.* item 47(d).

[11] *Ibid.* item 47(g).

ADJUSTMENT (AAC) WOULD PERMIT DELTA TO GAME THE SYSTEM? DO YOU AGREE?

A. No. Mr. Henkes argues that Delta could manipulate the budget in order to produce a higher revenue requirement in the first year of the mechanism(i.e., in the AAC), which would cause Delta to achieve earnings at the top end of the ROR range authorized by the Commission when costs are reconciled during the second year of the mechanism (i.e., in the AAF). This argument fails to consider several factors. First, the budgeted information used to calculate the AAC would be reviewed by the Commission. Second, Mr. Henkes fails to consider that too many variables exist for Delta to be able to "game the system." The uncertainty that exists regarding temperature and weather makes it extremely difficult for Delta to be able to manipulate the budget in order to earn at the top end of the range. Because variations in temperature have a major impact on earnings, and because Delta cannot predict what temperatures will be for the upcoming year, it would be impossible for Delta to project costs that would insure that it would earn at the top end of the range.

Mr. Henkes is worried that Delta may overestimate its costs and earn at the top end of the ROE range found reasonable by the Commission. As I have indicated, it would be extremely difficult for Delta to game the system in this way. Looking at his objection from another angle, it is obvious that he has a problem with Delta earning at the top end of range. I would like to point out that since the AAF provides a reconciliation of revenues collected under the AAC with actual historical costs, the AAF would bring Delta's earnings within the ROR range established by the Commission. Therefore, the final result would still be a return earned by Delta within the range authorized by the Commission. Mr. Henkes' expressed concern about a utility earning at the top end of the range says quite a lot about his objectives in this proceeding. Obviously, he is not worried about Delta earning below the bottom end of the range authorized by the Commission, preserving Delta's financial integrity, or reversing the steady erosion in the equity component of Delta's capital structure. Even if Delta could "game the system," which would be extremely difficult, Delta would still only earn a rate of return within the range authorized by the Commission.

Q. IS THERE AN ALTERNATIVE TO USING BUDGETED INFORMATION IN THE DETERMINATION OF THE AAC?

A. Yes. Instead of calculating the AAC using a budgeted return on common equity, as proposed by Delta, the AAC could be determined using Delta's actual return on common equity for the most recent fiscal year, adjusted for normal temperatures. With this approach, Delta would no longer be using budgeted earnings for purposes of determining the AAC, but rather, Delta would be using actual earnings adjusted for normal temperatures. Instead of implementing the AAC on July 1 of each year, the AAC would have to be implemented on October 1 in order to allow time for Delta to calculate the historical earnings for the fiscal year adjusted for normal temperatures.

Q. HAVE YOU PREPARED REVISED TARIFF SHEETS INCORPORATING THIS MODIFICATION?

A. Yes. Revised tariff sheets are included in SEELYE REBUTTAL EXHIBIT 5. The modification necessary to determine the AAC on the basis of actual temperature-normalized earnings appears on Sheet No. 31 of the tariff.

Q. ASSUMING THAT THE COMMISSION APPROVES THE PROPOSED CAPITAL STRUCTURE CONSISTING OF 43.5% EQUITY ARE THERE ANY OTHER CHANGES THAT NEED TO BE MADE TO THE ALT REG TARIFF SHEETS?

A. Yes. Sheet No. 33 needs to be modified to specify that Delta's average common equity shall not be more than 60% nor less than 43.5% of total capitalization. The original tariff specified that the average common equity would be limited to 60%. Since Delta has proposed to utilize an imputed capital structure in the determination of revenue requirements in the rate case, it is therefore appropriate to utilize this percentage in Delta's Alt Reg Plan. Otherwise, the Alt Reg Plan would nullify the use of an imputed capital structure in establishing base rates. These modifications are shown in SEELYE REBUTTAL EXHIBIT 5.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

SEELYE REBUTTAL

EXHIBIT 1

SEELYE REBUTTAL EXHIBIT 1

ACTUAL SLOPE AND INTERCEPT

Calculated by Applying Ordinary Least Squares to Actual Raw Data

y	x
4	1.5
4	1.5
4.75	2
5.5	2
5.75	2
6.25	2
6.5	2
7.25	2
2.5	3
1.5	3
2	3
2	3
9	4
4	6
4.5	6
8	6
8.25	6
8.45	6
9.2	6
13.6	6

Intercept	2.92392
Slope	0.80167

Note: The intercept and slopes are calculated by applying the "=Intercept( )" and "=Slope( )" functions in Microsoft EXCEL

SEELYE REBUTTAL

EXHIBIT 2

SEELYE REBUTTAL EXHIBIT 2

COMPARISON OF LEAST SQUARES METHODOLOGIES
APPLIED TO AVERAGE UNIT COST DATA

Ordinary Least Squares Applied to Average Unit Cost Data		Standard Weighted Least Squares Applied to Average Unit Cost Data Seelye Methodology			Dr. Estomin's Non-Standard Weighted Least Squares Model Applied to Average Unit Cost Data		
y	x	y*n^.5	n^.5	xn^.5	y*n	n	xn
4.00000	1.50	5.656854	1.414214	2.121320	8.000000	2.000000	3.000000
6.00000	2.00	14.696938	2.449490	4.898979	36.000000	6.000000	12.000000
2.00000	3.00	4.000000	2.000000	6.000000	8.000000	4.000000	12.000000
9.00000	4.00	9.000000	1.000000	4.000000	9.000000	1.000000	4.000000
8.00000	6.00	21.166010	2.645751	15.874508	56.000000	7.000000	42.000000
Intercept	2.62891		Intercept	2.92392		Intercept	3.33395
Slope	0.96094		Slope	0.80167		Slope	0.73491

Actual Slope and Intercept

Intercept	2.92392
Slope	0.80167

Note: the intercepts and slopes for the weighted least square models are calculated by applying the "=LINEST" function in Microsoft EXCEL with Constant set at "FALSE"

SEELYE REBUTTAL

EXHIBIT 3

SEELYE REBUTTAL EXHIBIT 3

Adjustment to Reflect Year-End Customers Over Average
For the 12 Months Ended December 31, 1998

	(1) 1998 Billings Cust.-Mos.	(2) Customers Served at Dec. 31, 1998 Annualized	(3) Year-End Over (Under) Average	(4) Customer Charge	(5) Additional Revenue (cust. Chg.)	(6) Weather Normalized Mcf	(7) Average Mcf per Customer per month	(8) Year-End Mcf Adjustment	(9) Rate per Mcf	(10) Additional Revenue (Mcf. Chgs)	(11) Year-End Revenue Adjustment
			col (2) - col (1)		col (4) x col (3)		col (6) x col (1)	col (7) x col (3)		col (9) x col (8)	col (5) + col (10)
REVENUE ADJUSTMENT											
Residential-Firm Sales	385,332	395,280	9,948	$ 8.00	$ 79,584	2,516,817	7	64,976		$ 176,812	$ 256,396
0.1 - 200 Mcf / mo.						2,516,817		64,976	$ 2.7212	176,812	
Small Commercial-Firm Sales	49,416	52,152	2,736	$ 18.36	50,233	647,063	13	35,826		97,160	147,393
0.1 - 200 Mcf / mo.						626,229		34,672	$ 2.7212	94,350	
200.1 - 1000 Mcf / mo.						17,501		969	$ 2.5000	2,422	
1000.1 - 5000 Mcf / mo.						3,333		185	$ 2.1000	388	
Large Commercial-Firm Sales	9,300	9,336	36	$ 25.00	900	928,389	100	3,594		9,395	10,295
0.1 - 200 Mcf / mo.						648,638		2,511	$ 2.7212	6,832.55	
200.1 - 1000 Mcf / mo.						202,059		782	$ 2.5000	1,955	
1000.1 - 5000 Mcf / mo.						67,218		260	$ 2.1000	546	
5000.1 - 10000 Mcf / mo.						10,474		41	$ 1.5000	61	
Industrial-Firm Sales	744	732	(12)	$ 25.00	(300)	168,119	226	(2,712)		(6,805)	(7,105)
0.1 - 200 Mcf / mo.						63,808		(1,029)	$ 2.7212	(2,801)	
200.1 - 1000 Mcf / mo.						73,121		(1,179)	$ 2.5000	(2,948)	
1000.1 - 5000 Mcf / mo.						31,189		(503)	$ 2.1000	(1,056)	
Com./Indust. Firm Transport.	600	600	-								
Com./Indust.-Interruptible Sales	84	84	-								
Com./Indust.-Interruptible Transport.	444	444	-								
Special Contract - Transport.	7	12	5			17,201		12,286		16,689	16,689
0.1 - 1000 Mcf / mo.						4,005		2,861	$ 1.7000	4,863	
1000.1 - 5000 Mcf / mo.						11,700		8,357	$ 1.3000	10,864	
5000.1 - 10000 Mcf / mo.						1,496		1,069	$ 0.9000	962	
Adjustment to Revenue					$ 130,417			113,970		$ 293,251	$ 423,668

EXPENSE ADJUSTMENT

Total Expenses per Books	22,875,094	
Less: Gas Supply Expenses	(14,147,177)	
Less: Wages and Salaries	-	
Net Expenses	$ 8,727,917	
Net Revenue as adjusted for the elimination of GSC revenues and a full-year at current rates	$18,677,538	
Operating Ratio	46.73%	46.73%
Adjustment to Expenses		$ 197,978

SEELYE REBUTTAL

EXHIBIT 4

SEELYE REBUTTAL EXHIBIT 4

Comparison of the Cost of Alternative Residential Energy Sources

Residential Energy Source	Current Estimated Cost ($/MMBtu on Input Basis)	Difference from Natural Gas ($/MMBtu)
Natural Gas	$6.69/MMBtu	$0.00/MMBtu
Electric Heating – Resistance (Kentucky Utilities)	$12.60/MMBtu	$5.91/MMBtu
Electric Heating – High Efficiency Heat Pump (Kentucky Utilities)	$7.00/MMBtu	$0.31/MMBtu
Propane	$11.51/MMBtu	$4.82/MMBtu
Fuel Oil (Summer Price)	$5.30/MMBtu	($1.39)/MMBtu
Coal (Customer Pickup)	$3.49/MMBtu	($3.20)/MMBtu

Note: This information was provided in response to item 17 of the Commission's Order in Case No. 99-046 dated June 4, 1999.

SEELYE REBUTTAL

EXHIBIT 5

FOR All Service Areas
P.S.C. NO. 9
Original SHEET NO. 30
CANCELLING P.S.C. NO. 8
SHEET NO.

DELTA NATURAL GAS COMPANY, INC.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE
RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

Applicability

Applicable to gas sold under the Company's General Service and Interruptible Rate Schedule and gas transported under the Transportation Of Gas For Others On System Utilization Rate Schedule.

Rate Mechanism

The monthly amount computed under each of the rate schedules to which this Alternative Ratemaking Mechanism is applicable shall include an Alternative Ratemaking Mechanism Adjustment Component (ARMAC) per Mcf of gas deliveries. The ARMAC to be applied to customer billings shall be equal to the sum of the following components:

$$ARMAC = AAC + AAF + BAF$$

The **AAC** is the Annual Adjustment Component per Mcf for each twelve month period during which this experimental alternative ratemaking mechanism is in effect. A discrete AAC charge or credit shall be computed for each applicable rate class billing block. Monthly bills shall be adjusted (increased or decreased) beginning July 1 of each fiscal year in accordance with the procedures described herein with respect to the return on common equity produced by the Company's budget for the fiscal year.

The **AAF** is the Actual Adjustment Factor per Mcf which, upon completion of the previous AAC period, reconciles any departures in the Company's earned return on common equity (ROE) that is outside the Commission's authorized ROE band-width. As with the AAC, a discrete charge or credit shall be computed for each applicable rate class billing block. Monthly bills shall be adjusted (increased or decreased) annually beginning October 1 of each year in accordance with the procedures described herein. The initial AAF would become effective on October 1 during the second year of the experimental mechanism following completion of the first year's AAC which would expire at the end of June.

The **BAF** is the Balance Adjustment Factor per Mcf which compensates for any differences between the amounts targeted and the amounts actually credited or charged upon application of the AAF and BAF. A single BAF charge or credit shall be calculated and shall apply uniformly to all applicable rate class billing blocks. Monthly bills shall be adjusted (increased or decreased) annually beginning January 1 of each year in accordance with the procedures described herein. The initial BAF would become effective on January 1 during the third year of the

DATE OF ISSUE July 2, 1999 DATE EFFECTIVE August 1, 1999
ISSUED BY Glenn R. Jennings TITLE President
Name of Officer
Issued by authority of an Order of the Public Service Commission of KY in
CASE NO. DATED

CLASSIFICATION OF SERVICE
RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

experimental mechanism following completion of the first year's AAF which would expire at the end of the previous September.

Calculation Procedures

Annual Adjustment Component (AAC)
The total amount from which the per Mcf AAC credits or charges are determined shall be calculated by:
1. comparing the budgeted return on common equity to the Commission authorized return on common equity, and
2. multiplying such difference by the 12-month average budgeted common equity; and
3. then adjusting the resulting deficient or excess earnings available for common equity for federal and state income taxes to determine the total amount of surcharge or credit for the twelve month AAC period.

However, in no case shall the total amount which the surcharge or credit is based exceed 5% of actual Company revenues during the most recent twelve month period for which actual results are available prior to the ACC filing.

Therefore, the total AAC amount shall be the lesser of:

$$((AROE - HROE) \times BCE) \div (1\text{-}SFIT) \quad \text{or} \quad AR \times 5\%$$

where:

AROE is the Commission authorized return on common equity, and
HROE is the actual historical return on common equity for the most recent fiscal year adjusted for normal temperatures, and
BCE is the is the budgeted common equity applicable to the 12 month AAC period based on the Company's budget as approved by its Board of Directors, and
SFIT is the applicable composite state and federal income tax rate.
AR is the actual revenue during the most recent twelve month period for which actual results are available prior to the filing of the AAC.

The Annual Adjustment Component (AAC) per Mcf applicable to each rate class billing block shall be calculated by multiplying the total AAC amount to be credited or surcharged, as calculated above, by the ratio of budgeted net revenue (exclusive of GCR revenue) in the applicable rate class billing block to the total budgeted net revenue of all applicable billing blocks in order to determine the amount applicable to the specific rate class

CLASSIFICATION OF SERVICE

RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

billing block. The resulting amount applicable to the specific billing block shall then be divided by the budgeted Mcf for such billing block to determine the AAC credit or charge per Mcf, as follows:

$$AAC = (\text{Total AAC Amount} \times (NRRB \div NRT)) \div RBMcf$$

where:

NRRB is the budgeted net revenue (exclusive of Gas Cost Recovery revenue) for the applicable rate class billing block in the Company's budget as approved by its Board of Directors and applicable to the 12 month AAC period (customer charge revenues are included in the initial billing of each rate class), and

NRT is the total budgeted net revenue of all rate class billing blocks to which this mechanism applies, and

RBMcf is the is the budgeted Mcf for the applicable rate class billing block.

Actual Adjustment Factor (AAF)

The total amount from which the AAF charges or credits are determined shall be calculated as follows:

1. The earned return on common equity at the end of the previous fiscal year is compared with the upper and lower limits of a return bandwidth which are ±50 basis points from the Commission authorized return on common. The earned return shall include amounts credited or charged under the AAC but shall not include amounts credited or charged under the AAF and the BAF.
2. If the earned return falls within the bandwidth, no Actual Adjustment Factor will be made.
3. If the earned return is higher than the upper limit or less than the lower limit of the bandwidth, such difference in return on common equity shall be multiplied by the actual 12-month average of common equity during the previous fiscal year to determine the amount of net income available for common which is subject to refund or recovery.
4. The net income subject to refund or recovery shall be adjusted for federal and state income taxes to determine the total amount of credit or surcharge for the twelve month AAF period.

Therefore, if the earned return on common is greater than the upper limit of the bandwidth, the amount of credit for the 12-month AAF period shall be determined in accordance with the following formula:

$$((ULROE - EROE) \times ACE) \div (1-SFIT)$$

However, if the earned return on common is less than the lower limit of the bandwidth, the amount of surcharge for the 12-month AAF period shall be determined in accordance with the following formula:

$$((LLROE - EROE) \times ACE) \div (1-SFIT)$$

	FOR All Service Areas
	P.S.C. NO. 9
DELTA NATURAL GAS COMPANY, INC.	Original SHEET NO. 33
Name of Issuing Corporation	CANCELLING P.S.C. NO. 8
	SHEET NO.

CLASSIFICATION OF SERVICE

RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

where:

ULROE is the upper limit of the bandwidth (50 basis points above the Commission authorized return on common equity), and

LLROE is the lower limit of the bandwidth (50 basis points below the Commission authorized return on common equity), and

EROE is the earned return on common equity achieved in the previous fiscal year, which includes amounts credited or charged under the AAC and excludes amounts credited or charged under the AAF and BAF, and

ACE is the is the actual 12 months average common equity during the previous fiscal year, and

SFIT is the applicable composite state and federal income tax rate.

Performance-Based Cost Controls

The non-gas supply operation and maintenance (O&M) expenses used to compute the earned return on common equity (EROE) shall be subject to the following performance-based cost controls:

(a) If the previous fiscal year's actual non-gas supply O&M expenses per customer are within plus (+) or minus (-) 1.50% of the non-gas supply O&M expenses (on a per customer basis) approved by the Commission for the test year in the Company's most recent adjustment of general rates (Case No. 97-066) after adjusting for changes in the Consumer Price Index for Urban Consumers (CPI-U) (the Indexed O&M Expenses), actual O&M expenses shall be used to compute the EROE.

(b) If the previous fiscal year's actual O&M expenses per customer exceed the Indexed O&M Expenses by more than 1.50%, Company shall be limited to the inclusion of only 50% of the expenses that are in excess of 101.50% of the Indexed O&M Expenses in computing its EROE.

(c) If the previous fiscal year's actual O&M expenses per customer are lower than the Indexed O&M Expenses by more than 1.50%, Company shall be allowed to increase the actual expenses used to compute the EROE by 50% of the amount by which the actual expenses are below 98.50% of the Indexed O&M Expenses.

The average common equity (ACE) for the previous fiscal year used for purposes of computing the Actual Adjustment Factor shall not be more than 60% of total capitalization nor less than 43.5% of total capitalization.

The Actual Adjustment Factor (AAF) per Mcf applicable to each rate class billing block shall be calculated by multiplying the total AAF amount to be credited or surcharged, as computed above, by the ratio of budgeted net revenue (exclusive of GCR revenue) in the applicable rate class billing block to the total budgeted net revenue of all applicable billing blocks in order to determine the amount applicable to the specific rate class billing block.

DATE OF ISSUE July 2, 1999 DATE EFFECTIVE August 1, 1999

ISSUED BY Glenn R. Jennings TITLE President

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CLASSIFICATION OF SERVICE

RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

The resulting amount applicable to the specific billing block shall then be divided by the budgeted Mcf for such billing block to determine the AAF credit or charge per Mcf, as follows:

$$AAF = (\text{Total AAF Amount} \times (NRRB \div NRT)) \div RBMcf$$

where:

NRRB is the budgeted net revenue (exclusive of Gas Cost Recovery revenue) for the applicable rate class billing block in the Company's budget as approved by its Board of Directors and applicable to the 12 month AAC period (customer charge revenues are included in the initial billing of each rate class), and

NRT is the total budgeted net revenue of all rate class billing blocks to which this mechanism applies, and

RBMcf is the is the budgeted Mcf for the applicable rate class billing block.

Balancing Adjustment Factor (BAF)

The BAF amount to be credited or charged shall be the accumulated differences between the amounts actually credited or charged under the AAF and the BAF from previous periods and the amounts used to establish the credits or charges (the targeted amounts) for such periods. The resulting BAF amount to be credited or charged shall be divided by the total budgeted Mcf sales and transportation volumes during the 12-month BAF period to determine the applicable BAF credit or charge per Mcf., as follows:

$$((AAFt - AAFa) + (BAFt - BAFa)) \div TBMcf$$

where:

AAFt is the amount used to establish the credit or charge during the previous AAF period (the targeted amount), and

AAFa is the actual amount credited or charged during the previous AAF period, and

BAFt is the amount used to establish the credit or charge during the second previous BAF period (the targeted amount), and

BAFa is the actual amount credited or charged during the second previous BAF period, and

TBMcf is the is the total budgeted Mcf for all applicable rate classes during the 12-month BAF period.

DELTA NATURAL GAS COMPANY, INC.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE
RATE SCHEDULES

EXPERIMENTAL ALTERNATIVE RATEMAKING MECHANISM

Information Provided by Company

1. Annual Operating Budget, as approved by the Company's Board of Directors, for the fiscal year that coincides with the 12-month period in which the Annual Adjustment Component (AAC) applies. This document shall be provided with the filing of the Annual Adjustment Component (AAC) on June 1 of each year.
2. Monthly budgeted net revenues (exclusive of gas supply costs) and Mcf sales of each rate class billing block for the sales and transportation rate classes to which this mechanism applies. The Company shall also include a monthly forecast of net revenues, by rate class billing block, for an additional three months beyond the budget-year along with a monthly forecast of Mcf sales and transportation, by rate class billing block, for an additional six months beyond the budget-year. This information shall be provided with the filing of the Annual Adjustment Component (AAC) on June 1 of each year.
3. Statement of Budgeted Income setting forth the calculations of expected net income available for common equity as well as the return on common equity for the budget-year along with the supporting documentation. This information and the supporting documents shall be provided with the filing of the Annual Adjustment Component (AAC) on June 1 of each year.
4. Statement showing the actual net revenues and Mcf sales for 12 months of the previous fiscal year. This information shall be provided with the filing of the Actual Adjustment Factor (AAF) on September 1 of each year.
5. Statement of Actual Income setting forth the calculations of actual net income available for common equity as well as the return on common equity for the previous fiscal year along with the supporting documentation. The calculations of net income available for common equity shall not include amounts credited or charged as result of application of the Actual Adjustment Factor (AAF) and/or the Balancing Adjustment Factor (BAF) under this mechanism. These calculations and the supporting documents shall be provided with the filing of the Actual Adjustment Factor (AAF) on September 1 of each year.
6. The Company will provide other information related to the Experimental Alternative Ratemaking Mechanism requested by the Commission.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF		
ADJUSTMENT OF RATES OF	)	CASE NO. 99-176
DELTA NATURAL GAS COMPANY, INC.	)	

REBUTTAL TESTIMONY OF

DR. MARTIN J. BLAKE

AFFIDAVIT

The affiant, Martin J. Blake, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared Rebuttal Testimony of this affiant in Case No. 99-176, in the matter of: Adjustment of Gas Service Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared Rebuttal Testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at any hearing in Case No. 99-176 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his Rebuttal Testimony in such case.

Martin Blake

Martin J. Blake

STATE OF KENTUCKY)

)

COUNTY OF JEFFERSON)

Subscribed and sworn to before me by Martin Blake, this the 20 day of October, 1999.

Angela D. Wilson
Notary Public, State at Large, KY
My Commission Expires: My Commission Expires July 28, 2001

Angela D. Wilson

Notary Public, State at Large, Kentucky

Q: PLEASE STATE YOUR NAME.

A: Martin Blake.

Q: ARE YOU THE SAME MARTIN BLAKE WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS DOCKET?

A: Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address the testimony filed by Attorney General Witness Carl G. K. Weaver in this proceeding. Dr. Weaver has not taken into account a number of relevant factors in estimating the return on equity that he recommends that the Commission use in determining Delta's revenue requirement in this proceeding. My rebuttal testimony will identify these factors and suggest appropriate corrections for these omitted factors. I will also address Mr. Henke's recommendation that the Commission deviate from its long-standing practice of determining revenue requirements by applying the authorized rate of return to total capitalization.

Q. WHAT FACTORS HAS DR. WEAVER FAILED TO PROPERLY TAKE INTO ACCOUNT IN HIS ANALYSIS?

A. The panel of five natural gas distribution companies that Dr. Weaver uses as the basis for his analysis, and which he claims are comparable to Delta, are in fact significantly different than Delta. These differences between Delta and the five companies in Dr. Weaver's panel result in significant differences in risk between Delta and these five companies. Dr. Weaver has not adequately taken these differences into account in recommending an allowed return on equity for Delta.

On page 38, lines 5-6 of his testimony, Dr. Weaver states that:

> First, I found that the five gas distribution companies are less risky than Delta. However, the difference in risk is small.

The conclusion that the difference in risk is "small" between Dr. Weaver's panel of five gas distribution companies and Delta does not adequately account for the significant differences in size between the five companies in the panel and Delta or the significant differences in equity ratios. I disagree with Dr. Weaver's statement that the differences in risk are "small". Later on page 38 in lines 15-17, Dr. Weaver states that:

> The cost of equity for the five companies would average 9.75% to 10.75%. I increased this range by 50 basis points to account for the greater risk of Delta. This results in the 10.25% to 11.25%.

Although Dr. Weaver carefully describes and documents his methodology earlier in his testimony for arriving at his estimate of the appropriate return on equity for the five company panel, he provides no explanation of how he arrived at the addition of 50 basis points to account for Delta's increased risk. As it stands, it is a totally unsupported number. In my opinion, 50 basis points does not begin to capture the difference in risk between Delta and Dr. Weaver's five company panel.

Q. WHAT RISK FACTORS HAS DR. WEAVER NOT PROPERLY QUANTIFIED IN ARRIVING AT A 50 BASIS POINT DIFFERENCE IN RETURN IN EQUITY BETWEEN DELTA AND HIS FIVE COMPANY PANEL?

A. Dr. Weaver has not properly accounted for a number of factors including 1) Delta's larger residential and commercial load than the five company panel which would make Delta more adversely affected by weather, 2) Delta's smaller size relative to the five companies, 3) Delta's significantly lower equity ratio compared to the five companies, and 4) Delta's rural and largely mountainous service territory which requires a greater investment in assets to provide service, as well as a number of other financial factors. The addition to risk resulting from a number of these factors is difficult to quantify, although directionally it can be said that they will increase Delta's risk compared to the other five companies. However, the impact of Delta's smaller size and lower percentage of equity can be quantified.

Q. PLEASE EXPLAIN HOW THE RETURN ON EQUITY THAT DR. WEAVER FOUND APPROPRIATE FOR HIS FIVE COMPANY PANEL COULD BE ADJUSTED TO REFLECT DELTA'S LOWER EQUITY RATIO.

A. The first element that is necessary to quantify the appropriate leverage premium is the difference in equity ratios between Dr. Weaver's five company panel and Delta. Whether using the data in Schedule 3 of Dr. Weaver's testimony (45.7% - 36.2% = 9.5%), the data from page 16 of Dr. Weaver's testimony (49.2% - 38.5% = 10.7%) or the data from Exhibit MJB-1 (41% - 30.6% = 10.4%), the difference in the equity ratio between Dr. Weaver's five company panel and Delta is about 10%. The differences stem mainly from whether to include short term debt in calculating the equity ratio. However, whether short term debt is included or excluded, the five company panel has an equity ratio that is about 10% higher than Delta.

On page 14 of his testimony, Dr. Weaver recognizes that increased leverage will increase risk noting that:

> Leverage, measured by the mix of debt and equity capital, is a source of risk to companies. Financial risk results from two sources: (1) the fixed interest charges and principal repayment provisions associated with debt that, contractually, must be paid or the company would be in default and (2) the increase in the variability of earnings per share that is caused by leverage.

However, after noting the increased risk caused by increased leverage, Dr. Weaver makes no attempt to quantify the additional risk associated with Delta due to its significantly lower equity ratio. As noted above, he dismisses these differences as "small" and, without support, adds an additional 50 basis points to the estimated return on equity for the five company panel of account for this as well as all of the other increased risk factors associated with Delta. Dr. Weaver's dismissal of the impact as "small" are not consistent with published research on this topic. The magnitude of an appropriate leverage adjustment to account for Delta's lower equity ratio can be derived from research published by Brigham, Gapenski and Aberwald which addressed the question: How do changes in capital structure affect the cost of equity? In their article, Brigham, Gapenski and Aberwald state that:

> We concluded that a one percentage point change in the debt ratio causes, on average, a change of about 12 basis points in the cost of equity. (Eugene F. Brigham, Louis C. Gapenski and Dana A. Aberwald, "Capital Structure, Cost of Capital, and Revenue Requirements", Public Utilities Fortnightly, January 8, 1987, p. 15)

In explaining the nature of the underlying relationship that resulted in this 12 basis point average, they went on to note that:

> The basis change is smaller toward the high end of the equity ratio range, so an increase in equity from 49 to 50 per cent would only lower the cost of equity by about seven basis points, but an increase in the ratio from 40 to 41 per cent would lower the cost of equity by about 15 basis points. (Eugene F. Brigham, Louis C. Gapenski and Dana A. Aberwald, "Capital Structure, Cost of Capital, and Revenue Requirements", Public Utilities Fortnightly, January 8, 1987, p. 23)

This quote makes it clear that the increase in return on equity necessary to compensate for each percentage point decrease in the equity ratio is larger in the lower ranges of equity ratios. Because of Delta's low equity ratio, I believe that it would be appropriate to use a leverage premium of 15 basis points for each percentage point that Delta is below the average of the five company panel. Applying this 15 basis point premium to Delta's 10% lower equity ratio than the five company panel average, produces an addition of 150 basis points to the estimated return on equity for the 5 company panel in order to properly account for this risk factor. Properly accounting for this leverage risk factor alone produces an addition to Delta's return on equity that is three times larger than the 50 basis point addition that Dr. Weaver is recommending, without support, to account for the impact of all additional risk factors. Even if a very conservative quantification of 12 basis points is used for each percentage point that Delta is below the average of the five company panel, the result would still be an additional 120 basis points added to the estimated return on equity for Dr. Weaver's five company panel. Properly quantifying this risk factor and adding it to Dr. Weaver's estimated return on equity for the five company panel would produce a return on equity for Delta in the 11.25% to 12.25% range.

Q. PLEASE EXPLAIN HOW THE RETURN ON EQUITY THAT DR. WEAVER FOUND APPROPRIATE FOR HIS FIVE COMPANY PANEL COULD BE ADJUSTED TO REFLECT DELTA'S SMALLER SIZE.

A. Dr. Weaver's Schedule 1 illustrates the significant size differences that exist between his five company panel and Delta. The smallest member of the five company panel has more than 3 times the total assets of Delta, while the largest member of the panel has assets that are about 10 times as large as Delta's. A comparable panel would have companies of approximately the same size or at least companies which bracket Delta, with some companies in the panel larger and some smaller. To have a panel composed of companies that are all significantly larger than Delta does not constitute a comparable panel in my opinion. The fact that the five company panel is not comparable to Delta is not fatal, however. The results of the analysis of the five company panel can be made comparable by adjusting for risk factors where there are significant differences. Based on published research, size is one of the significant differences that must be corrected after the fact if comparable results are to be achieved. Small companies such as Delta are riskier than companies with larger capitalizations and a higher rate of return on equity would be appropriate for these smaller companies.

Pages 19 and 20 of my Direct testimony refer to published research by Fama and French and by Ibbotson Associates that aid in quantifying the additional return on equity that would be appropriate due to Delta's smaller size. Exhibit MJB-6 shows the size premia that would be appropriate for companies with different levels of capitalization. Based on Dr. Weaver's Schedule 1, four members of his panel would fall in the "Low-capitalization" group (capitalization between $252 and $918 million) and one member of his panel would fall within the "Mid-capitalization" group (capitalization between $918 and $4,200 million). Delta would fall in the "Micro-capitalization" group (capitalization below $252 million). The difference in size premium between the "Low- capitalization" group and the "Micro-capitalization" group is 150 basis points (2.6% - 1.1%). The difference in size premium between the "Mid- capitalization" group and the "Micro-capitalization" group is 210 basis points (2.6% - 0.5%). In my opinion, it is necessary to add 150 basis points to the return on equity that Dr. Weaver found to be appropriate for his five company panel in order to adequately take into account the impact of the different size of the companies in his panel compared to Delta. Again, his unsupported 50 basis point addition for all additional risk factors is woefully inadequate.

Q. WHAT IS THE RESULT OF ADJUSTING THE RETURN ON EQUITY ESTIMATED BY DR. WEAVER FOR HIS FIVE COMPANY PANEL FOR BOTH THE DIFFERENCES IN LEVERAGE AND SIZE BETWEEN HIS PANEL AND DELTA?

A. The cost of equity that Dr. Weaver estimated for his five company panel ranged from 9.75% to 10.75%. To this range he added an unsupported and unexplained 50 basis points to take account of Delta's "small" additional risk. The size differences and leverage differences between Delta and Dr. Weaver's five company panel would justify an addition of 300 basis points to account for the impacts of these two risk factors alone. This is not a "small" difference in risk, as Dr. Weaver claims. Furthermore, the quantification of the additional return on equity necessary to adjust for these size and leverage differences between Delta and the five company panel is explained fully and supported by published research. When the 300 basis point adjustment for these two factors is added, the result is a return on equity in the range of 12.75% to 13.75%. If an imputed capital structure were utilized, a 150 point adjustment to Dr. Weaver's results would be appropriate to take account of the significant difference in size. This would result in a return on equity in the 11.25% to 12.25% range with the use of an imputed capital structure, or a return on equity in the 12.75% to 13.75% range without the use of an imputed capital structure. These results obtained by adjusting Dr. Weaver's results for the appropriate risk factors are very similar to the recommendations that I make in my Direct Testimony. On page 28 of my Direct Testimony, I recommend using a 11.9% return on equity with an imputed capital structure or a 13.9% return on equity without an imputed capital structure. It appears that after adjusting Dr. Weaver's results for the appropriate risk factors to account for the significant differences between Delta and his five company panel, his results and mine are very similar even though we got there by taking different approaches.

Q. DO YOU STILL BELIEVE THAT THE USE OF AN IMPUTED CAPITAL STRUCTURE IS APPROPRIATE IN THIS CASE?

A. Yes. The equity component of Delta's capital structure has been steadily eroding for 10 years. The use of an imputed capital structure would generate the earnings necessary to turn this around and to re-build Delta's equity. Use of an imputed capital structure would allow the Commission to accomplish this while using an allowed return on equity of 11.9%. If the Commission does not use an imputed capital structure, it would be necessary to add a leverage adjustment of between 150 and 200 basis points, resulting in a return on equity in the 13.4% to 13.9% range. Although this range of returns is justified by the additional risk that Delta faces resulting from its low percentage of equity, it may be larger than the Commission would feel comfortable allowing. An imputed capital structure is simply another way of correcting for this additional risk factor.

Q. WHAT IS YOUR UNDERSTANDING OF DR. WEAVER'S POSITION ON THE USE OF AN IMPUTED CAPITAL STRUCTURE?

A. On page 8, line 10 of the testimony that he filed on September 23, 1999, Dr. Weaver states that, "The use of a hypothetical capital structure is a fiction that simply does not exist." However, on page 2, lines 14-16 of the testimony that he filed in this proceeding on July 30, 1999, Dr. Weaver states that:

> When setting rates, the Commission could use a hypothetical capital structure if it finds that the capital structure chosen by management has excessive equity capital.

It appears to me that Dr. Weaver is in favor of imputed capital structures when they have a negative impact in calculating the revenue requirement, but strongly opposed to them when they have a positive impact in calculating the revenue requirement. In reality, an imputed capital structure is a tool available to Commissions when the equity ratio for a company is either to high or too low. In this proceeding, Delta's actual capital structure clearly has an equity component that is too low and the use of an imputed capital structure would be appropriate in this case.

Q. ON PAGE 8 OF HIS TESTIMONY, DR. WEAVER CLAIMS THAT "THE FINANCIAL INTEGRITY MANDATE IS ALSO MET BY USING CAPITAL MARKET DATA". DO YOU AGREE WITH THIS STATEMENT?

A. No. This statement demonstrates a focus on inputs rather than outputs or results. Financial integrity is not ensured because of the use of a certain set of data. The methods of analysis and the results are also important. Although capital market data have been used in past rate cases, preserving Delta's financial integrity has clearly not been the result. The equity component of its capital structure has steadily eroded over the last ten years. Starting from 46.5% of its total capitalization in 1988, the equity component of Delta's capital structure has steadily declined to about 31% at the end of the test year in this proceeding. This is a compound annual rate of decline in the equity component of Delta's capital structure of about 3.75% per year over the 11 year period. As shown in Exhibit MJB-1, Delta has the second lowest equity component of the 29 gas distribution utilities in the Edward Jones panel and is well below the median equity component of 43.9% for the panel. As page 2 of Exhibit MJB-2 illustrates, Delta has had a payout ratio of greater than 100% in 6 of the last 10 years with an average payout of 105%. Page 2 of Exhibit MJB-5 shows that in 1998, Delta had one of the highest payout ratios in the panel of 29 natural gas distribution utilities. Such a payout ratio cannot be maintained in the long run. Page 1 of Exhibit MJB-5 shows that Delta has one of the lowest interest coverages in the panel of 29 natural gas distribution utilities. Page 4 of Exhibit MJB-5 shows that Delta has one of the lowest market to book values in the panel of 29 natural gas distribution utilities. Page 2 of Exhibit MJB-2 shows that Delta earned a return on equity of 8.22% during 1998, a return on equity of 5.85% during 1997 and averaged a 10.1% return on equity over the period 1989 to 1998. In short, Delta is high on the financial measures that it is good to be low on, low on the financial measures that it is good to be high on, and has experienced an almost continual decline in the equity component of its capital structure over the last 10 years. In my opinion, these are all unmistakable signs of financial distress. Delta's S&P relative strength rank of 32 as reported by Dr. Weaver on page 23, line 10 of his testimony would seem to support my analysis. Delta's S&P relative strength rank of 32 is well below the average of 68 for his five company panel and is a full 11 points below the lowest member of his five company panel. These relative strength rankings do not bracket Delta and provide additional indication to me that Dr. Weaver's panel is not comparable to Delta.

Later on page 8, lines 14-17, Dr. Weaver claims that:

> the use of capital market price data in the analysis causes the results to be in compliance with the Bluefield and Hope mandates that the return (1) be comparable to the return earned by other firms with similar risk, (2) preserve the firm's financial integrity, and (3) enable it to attract capital.

Again, Dr. Weaver is focusing on inputs rather than results. As noted above, the financial results have not been good for Delta and it is experiencing financial distress. A company does not have to be unable to meet its current financial obligations when they become due in order to experience financial distress. Financial distress sets in well before the time that a company goes bankrupt. I don't believe that the requirement to preserve a utility's financial integrity found in Hope and Bluefield means that as long as the company is not bankrupt the requirement is met. Delta is providing a valuable service to rural residents of Kentucky and the Commission needs to take action to reverse Delta's alarming financial trends described above if Delta is to continue to provide this service in the long run.

Q. ON PAGE 8 OF HIS SEPTEMBER 23, 1999 TESTIMONY, DR. WEAVER CLAIMS THAT DELTA'S CAPITAL STRUCTURE IS A RESULT OF MANAGEMENT CHOICE AND THAT DELTA SHOULD NOT BE GIVEN A "BONUS" RETURN SIMPLY BECAUSE ITS MANAGEMENT HAS CHOSEN TO HAVE MORE DEBT THAN AN AVERAGE GAS DISTRIBUTION COMPANY. DO YOU AGREE WITH THIS STATEMENT?

A. No. In my opinion, the steady erosion of the equity component of Delta's capital structure is caused by poor earnings and the financial distress that it is experiencing, which I have described in my response to the preceding question. As I have demonstrated above from references to published research, Delta's low equity component is a substantial additional risk factor which would require an upward adjustment of about 150 basis points in Delta's return on equity to correct. It is ludicrous to suggest that a company would consciously choose to have the equity component of its capital structure erode over a 10 year period from 46.5% of its total capitalization in 1988 to about 31% at the end of the test year in this proceeding. This lower equity component magnifies the impact of any revenue fluctuations on Delta and substantially increases Delta's risk. Dr. Weaver has not identified any reasons why a management team would find it to their advantage to consciously choose for their equity ratio to steadily erode, and his statement that Delta's existing capital structure is a matter of management choice should be given the weight that it deserves and ignored by the Commission.

Q. ONE OF THE SELECTION CRITERIA THAT DR. WEAVER USED IN SELECTING HIS FIVE COMPANY PANEL WAS THE NET SALES TO TOTAL ASSETS RATIO.

Q. IN YOUR OPINION, ARE THE FIVE COMPANIES IN THE PANEL SIMILAR TO DELTA WITH RESPECT TO THE NET SALES TO TOTAL ASSETS RATIO?

A. No, the five companies in Dr. Weaver's panel are not similar to Delta with respect to the net sales to total assets ratio. The 1996-98 average net sales to total assets ratio averages 59% for the five companies in his panel and is not lower than 55% for any of the five companies. This is in contrast to the 44% net sales to total assets ratio for Delta for the same period. Thus, Delta generates substantially less sales per dollar of assets than the five companies in Dr. Weaver's panel, or looking at it from a different perspective, it takes more assets for Delta to generate a dollar of sales than the five companies in Dr. Weaver's panel. Combined with the fact that Delta has three times less assets than the smallest member of Dr. Weaver's panel leads me to conclude that Dr. Weaver's five company panel is not comparable to Delta and that these differences must be accounted for in the analysis. On page 15, lines 17-20 of his testimony, Dr. Weaver states that:

> Delta being located in a rural and largely mountainous region requires a greater investment to provide service. However, on a relative basis, the five companies selected have an investment closer to Delta than the other companies listed by Value Line.

Just because the five companies that he selects are closer than other natural gas distribution companies that are even more dissimilar than Delta does not make his five company panel comparable. It should be noted that in Dr. Weaver's Schedule 2, only one company has a lower 1996-98 average net sales to total assets ratio than Delta, and this company was not included in the panel. Dr. Weaver has not selected companies that bracket Delta, i.e. some above and some below, but which are consistently above Delta.

Because Dr. Weaver's five company panel is not comparable, the differences must be accounted for through adjustments made to the return on equity estimated for the panel.

Q. ON PAGES 17-21 OF HIS TESTIMONY, DR. WEAVER EXAMINES A NUMBER OF DIFFERENT CASH FLOW COVERAGES. PLEASE COMMENT ON HIS CASH FLOW ANALYSIS.

A. On page 17, lines14-16 of his testimony, Dr. Weaver states that:

> The coverage ratios that I use are calculated from "cash flow from operating activities" that is defined by FASB 95.

I believe that a better picture of interest coverage is obtained by using net income before interest and taxes rather than with respect to cash flow. It is net income before interest and taxes that is available for a company to make its interest payments. Page 1 of Exhibit MJB-5 provides the ratio of net income before interest and taxes to total interest charges for 29 natural gas distribution companies, four of which are in Dr. Weaver's five company panel. Delta's interest coverage of 1.75 calculated as the ratio of net income before interest and taxes to total interest charges is the second lowest of the 29 companies and is well below the average of 2.55 for Connecticut Energy Corporation, CTG Resources, Cascade Natural Gas, and South Jersey Industries from Dr. Weaver's panel. Again, none of the five companies in Dr. Weaver's panel are below Delta with regard to interest coverage, and his panel does not bracket Delta in this respect.

On page 20 of his testimony, Dr. Weaver claims that the cash flow coverage of net income is a measure of the quality of earnings. He goes on to note that with respect to cash flow coverage of net income:

> Delta's coverage measure averaged 3.62 times while the coverage measure for the nine (sic) companies averaged 1.96 times. (page 20, lines 19-20)

Based on this, Dr. Weaver concludes that Delta's reported net income is of high quality. Another interpretation of this ratio is that it takes Delta $3.62 of cash flow to generate a dollar of net income, while it takes the five companies in Dr. Weaver's panel only an average of $1.96 in cash flow to generate a dollar of earnings. Being able to generate a dollar of earnings with a smaller cash flow clearly makes Dr. Weaver's five company panel less risky than Delta. It takes almost twice as much cash flow for Delta to generate a dollar of earnings than the five companies in Dr. Weaver's panel. I would interpret this difference in cash flow coverage of net income as yet another indicator that Delta is more risky than Dr. Weaver's panel and disagree with his assessment that "the quality of earnings tends to make Delta less risky than the other companies." (Weaver Testimony, page 21, lines 11-12). Similarly, Delta's higher cash flow coverage of dividends reported by Dr. Weaver on page 19 of his testimony indicates that it takes Delta more dollars of cash flow to generate a dollar of dividends than Dr. Weaver's five company panel.

Q. ON PAGE 22 OF HIS TESTIMONY, DR. WEAVER NOTES THAT THE S&P BETA FOR DELTA IS .02 AND STATES THAT THIS INDICATES THAT DELTA HAS EVEN LESS SYSTEMATIC RISK THAN THE AVERAGE COMPANY. DO YOU AGREE WITH HIS ASSESSMENT?

A. No, I do not agree with his assessment. As I noted on page 26 of my Direct Testimony, the formula used to estimate the beta for a company is:

$$K = R_f + \mathrm{B}(R_m - R_f)$$

where:

K = the prospective market cost of equity for a specific investment,

R_f = the risk free rate of return (usually U.S. Treasury bonds for estimating ROE),

β = the company specific beta coefficient, and

R_m = the overall stock market return (usually the S&P 500 Index for estimating ROE).

The beta parameter in this relationship is estimated using ordinary least squares (OLS) regression. There are statistics that are commonly used to measure the goodness of fit for an estimated OLS regression, such as the R^2, the t-values for each estimated parameter, and the F-value for the equation as a whole. These measures of goodness of fit are used to indicate whether confidence can be placed in the estimated parameters. The 0.02 beta reported by S&P could be interpreted in two ways. The first is the interpretation used by Dr. Weaver that Delta has less systematic risk than the average company. This interpretation would be appropriate if the R^2 for the estimated relationship were high, the t-value for the beta estimate were significant and the F-value for the equation as a whole were significant. Another possible interpretation is that there is no real underlying relationship, that the underlying data are random, and that the beta estimate is meaningless. This interpretation would be appropriate if the R^2 for the estimated relationship were low, the t-value for the beta estimate was not significant and the F-value for the equation as a whole was not significant. To determine whether the estimated relationship was strong and should be given weight in the analysis, I called Standard & Poor's Securities and talked to Craig Shere, the analyst that covers Delta. I asked if the goodness of fit information was available for the estimated beta coefficient so that I could determine which interpretation would be appropriate. He said that, because of the large number of companies tracked by Standard & Poor's, the numerical data at the beginning of each stock report was the result of a mechanized calculation of the reported parameters and that the goodness of fit measures were neither reported nor considered. Having taught econometrics for fourteen years and having conducted numerous econometric analyses, I am well aware that if you put data into an OLS regression package you will get numbers out. Whether those numbers are good estimates that can be relied upon is why the goodness of fit measures are so closely scrutinized. Because there are two alternative interpretations of an estimated beta, it is particularly important to check the goodness of fit measures if the estimated beta is nearly zero as a parameter estimate of this magnitude is very likely an indicator of randomness and no underlying relationship. Because there is no goodness of fit support available for the beta estimate of 0.02, it is my opinion that no weight should be given to a beta estimate of 0.02 in this proceeding. This conclusion was supported by my discussion with Mr. Shere. When I pointed out the two alternative interpretations and indicated why I needed the goodness of fit information to distinguish between them, Mr. Shere indicated that analysts are well aware that "small cap stocks don't correlate to the S&P 500." As noted above, Delta is a very small cap stock and is classified in the smallest capitalization group according to Ibbotson and Associates. This would support my conclusion that there is no underlying relationship and that the beta estimate of 0.02 is meaningless and should not be considered in this proceeding unless those relying on it can provide the goodness of fit information to support its use.

Q. ON PAGE 24 OF HIS TESTIMONY, DR. WEAVER DRAWS THE CONCLUSION THAT DELTA IS LESS RISKY THAN AN AVERAGE COMPANY. DO YOU AGREE WITH HIS CONCLUSION?

A. No, I do not. On page 24, lines 11-14 of his testimony, Dr. Weaver states that:

> The published market measures indicate that the five companies are less risky than an average company. This indicates that the cost of equity for these companies should be lower than the cost rate for an average company. Since Delta is similar to these five companies, it is also less risky than an average company.

As I have demonstrated above, Delta is not similar to Dr. Weaver's five company panel, and this conclusion is a logical fallacy. The companies in Dr. Weaver's panel almost never bracket Delta and are not representative of Delta or its financial condition. Also as I noted above, these significant differences between Delta and Dr. Weaver's five company panel are not fatal to his analysis if appropriate adjustments to his estimated return on equity are made to correct for these differences.

Q. ON PAGE 30 OF HIS TESTIMONY, DR. WEAVER MAKES THE OBSERVATION THAT, IN SPITE OF THE EPS VARIABILITY, DELTA WAS ABLE TO MAINTAIN A RELATIVELY CONSTANT AND SLOWLY GROWING DIVIDEND. PLEASE COMMENT ON THIS OBSERVATION.

A. In making this observation, Dr. Weaver failed to note that the equity component of Delta's capital structure was steadily eroding during the same 10 year period that he mentions. Thus, the "relatively constant and slowly growing dividend" should not be considered in isolation but in the context of the other financial conditions that existed at Delta.

Q. DO YOU AGREE WITH DR. WEAVER'S RECOMMENDATION REGARDING DELTA'S COST OF EQUITY IF THE PROPOSED ARP IS ADOPTED?

A. No. On page 43, lines 19-20 of his testimony, Dr. Weaver recommends that the cost of equity should be from 8% to 9% if the proposed ARP is adopted. He arrives at this conclusion by making an arbitrary and unsupported 25% reduction in the equity risk premium. The low end of this recommended range is below the Baa Utility Bond Yield of 8.14% reported for August, 1999 in Dr. Weaver's Schedule 19. Thus, his recommendation would have the equity return for Delta near or below the average utility bond rate. In my opinion this is not appropriate given the experimental nature of the ARP and the 3 year period for which it would be in effect. On page 42, lines 4-7 of his testimony, Dr. Weaver appears to agree with me about the uncertainty regarding the ARP when he states that:

> It is not certain at this time what modifications might need to be made to the ARP if it is approved in its present form. There could be changes that need to be made to prevent over- or under-earning. There is natural scepticism that investors will have until the ARP has been tested by time.

Yet, after correctly recognizing that it is difficult to tell how this experimental, 3 year program will affect investors, Dr. Weaver makes a recommendation to reduce the return on equity to near or below his most recent reported yield for Baa utility bonds. Reducing Delta's return on equity as Dr. Weaver recommends would not be consistent with the experimental and time-limited nature of the proposed ARP and would not be consistent with the Commission's responsibilities under Bluefield and Hope.

Q. WHY DO YOU SAY THAT THE REDUCED RETURN ON EQUITY RECOMMENDED BY DR. WEAVER IF THE ARP IS ADOPTED WOULD NOT BE CONSISTENT WITH THE COMMISSION'S RESPONSIBILITIES UNDER BLUEFIELD AND HOPE?

A. If the ARP is adopted, Dr. Weaver recommends that the Commission allow Delta a return on equity in the 8% to 9% range. (Weaver Testimony, page 43, line19). This recommended rate of return on equity is so low that it would not even cover Delta's current dividends. At the end of the test year on December 31, 1998, Delta had 2,394,633 shares of common stock outstanding and paid an annual dividend of $1.14 per share. Multiplying the number of shares by the dividends per share results in total dividends of $2,729,882. Dividing total dividends by the test year end equity of $28,351,812 yields 9.6%. Thus, just to pay its current dividends, Delta would need a 9.6% return on equity. With the 8% to 9% return on equity recommended by Dr. Weaver, Delta could not even pay its current dividends, let alone provide sufficient returns to reverse the steady erosion in the equity component of Delta's capital structure. This is not consistent with the Commission's responsibilities under Bluefield and Hope as I understand them.

Q. BASED ON YOUR ANALYSIS OF DR. WEAVER'S TESTIMONY, DO YOU STILL SUPPORT THE RECOMMENDATIONS THAT YOU MADE IN YOUR DIRECT TESTIMONY?

A. Yes. I recommend using an imputed capital structure consisting of 43.5% equity and 56.5% debt with an allowed return on equity of 11.9% for use in calculating Delta's revenue requirement. As an alternative the Commission could allow Delta a 13.9% return on equity without the use of an imputed capital structure. These are simply two different ways of taking into account the significantly lower equity ratio that Delta has and would be a positive first step in reversing the steady erosion in the equity component of Delta's capital structure that has been occurring over the past ten years.

Q. ON PAGES 9-10 OF HIS TESTIMONY MR. HENKES ARGUES THAT HIS RECOMMENDED RATE OF RETURN SHOULD BE APPLIED TO RATE BASE RATHER THAN TOTAL CAPITALIZATION. DO YOU AGREE WITH THIS APPROACH?

A. No. In his schedule RJH-2, Mr. Henkes calculates an overall weighted rate of return on total capitalization then applies this rate of return to rate base for purposes of calculating revenue requirements. It is not appropriate to mix apples and oranges by calculating the rate of return based on <u>*total capitalization*</u> and then applying it to <u>*rate base*</u>. The Commission has a longstanding practice of calculating the return for each component of capital and then applying the overall weighted return to *total capitalization* for determining revenue requirements. The rate of return on rate base is simply a calculated result determined by dividing the return on total capitalization by the utility's rate base.

The Commission has adhered to this practice in all of Delta's rate cases prior to its last case and in all of LG&E's rate cases. For example, the Commission ruled as follows in LG&E's last rate case:

> Applying the rates of 7.79 percent for debt, 9.09 percent for preferred stock, and 12.50 percent for common equity to the capital structure produces an overall cost of capital of 9.89 percent, which we find to be fair, just and reasonable. This cost of capital produces a rate of return on LG&E's net original cost rate base of 9.52 percent which the Commission finds is fair, just and reasonable. (*Order, Case No. 90-158*, dated December 21, 1990, page 54.)

Sometimes rate base is higher than total capitalization and sometimes it is lower. Rate base can differ from total capitalization for a number of reasons (e.g., because of cash working capital.) It is not appropriate to pick and choose whichever methodology produces the lowest revenue requirements.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF ADJUSTMENT	)	
OF RATES OF	)	CASE NO. 99-176
DELTA NATURAL GAS COMPANY, INC.	)	

REBUTTAL TESTIMONY OF

JOHN BRADLEY BROWN

AFFIDAVIT

The affiant, John Bradley Brown, being duly sworn, deposes and states that the prepared testimony attached hereto and made a part hereof, constitutes the prepared rebuttal testimony of this affiant in Case No. 99-176, in the Matter of: Adjustment of Gas Service Rates of Delta Natural Gas Company, Inc. and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached rebuttal testimony.

Affiant further states that he will be present and available for cross-examination and for such additional direct examination as may be appropriate at any hearing in Case No. 99-176 scheduled by the Commission, at which time affiant will further reaffirm the attached testimony as his rebuttal testimony in such case.

John Bradley Brown

John Bradley Brown

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Subscribed and sworn to before me by John Bradley Brown, this the 21st day of, October 1999.

My Commission Expires: July 11, 2001

Notary Public, State at Large, Kentucky

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John Bradley Brown and my business address is Delta Natural Gas Co., Inc.; 3617 Lexington Road; Winchester, Kentucky 40391.

Q. ARE YOU THE SAME JOHN B. BROWN THAT SUBMITTED TESTIMONY ON BEHALF OF DELTA NATURAL GAS COMPANY, INC. WHICH WAS FILED WITH THE COMMISSION ON JULY 2, 1999, IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the direct testimony filed with the Kentucky Public Service Commission ("Commission") in September 1999 by Robert J. Henkes with regard to general adjustments to Delta's rates. My rebuttal testimony will deal with Mr. Henke's proposed adjustments to Pension Expense Adjustment, 401(k) Expense Adjustment, Regulatory Expense Adjustment, Bad Debt Adjustment and Miscellaneous Expense Adjustment.

Q. IN RJH-9, HENKES LISTS SEVERAL EXPENSE ITEMS THAT HE HAS SINGLED OUT FROM THE TEST YEAR AS NOT BEING "REPRESENTATIVE" OF FUTURE EXPENSE. DO YOU TAKE ISSUE WITH ANY OF THESE ITEMS?

A. Yes. Specifically the Pension Expense Adjustment, 410(k) Expense Adjustment, Regulatory Expense Adjustment, Bad Debt Expense Adjustment and Miscellaneous Expense Adjustment.

Q. WHAT IS YOUR CONCERN WITH THE HENKES APPROACH?

A. In addition to some specific errors in fact which are pointed out separately throughout this testimony, Henkes' general approach is deliberately biased against a representative test year. Henkes' definition of "reasonable expense" includes a downward adjustment for certain expense items which he alleges were unusually high during the test year. Henkes chose to ignore the fact that items of even greater magnitude were unusually low. The fact that Delta's book O&M expenses in total for the calendar year 1997 and 1998 (the test year) were virtually the same between the years ($8,727,918 in 98 vs. $8,728,133 in 97) demonstrates that, as a whole, Delta's 1998 O&M expenses showed no unusual increases that would render the test year as non-representative for purposes of rate-making. Arbitrarily singling out certain expense items to disallow while ignoring other expenses that decreased clearly distorts the test year revenue requirements by understating O&M expenses in total. Inasmuch as certain expenses are reasonably expected to increase (i.e. payroll), this leads one to believe that there are more understated expense items in the test year than overstated ones. If specific expenses, deemed to be high, are going to be reduced, it is unfair and inappropriate not to consider other expense items that decreased during the test year.

Q. WILL YOU NAME A FEW OF THESE ACCOUNTS THAT ARE UNUSUALLY LOW DURING THE TEST YEAR?

A. Yes. The following analysis details a few of such accounts:

<u>A/ C 1.926.04 Medical Coverage</u>

The test year amount of $729,269 of Medical Coverage is clearly understated and will not grant sufficient recovery in a normal year. The 1997 amount was $889,796, or $160,528 higher. Looking ahead substantiates this claim further. The June 30, 2000 fiscal year budget is $900,000. Calendar year experience to date (to August 31) plus 4 months budget amounts to $1,042,693. The Company followed a similar methodology in determining a recommended amount for medical coverage as the Attorney General applied to bad debt expense on Sch. RJH-14. The most current information was used to capture most accurately the trend of rising health costs.

		Medical Plan Expense	Payroll	Medical Plan Exp as a % of Payroll
1997		$889,796	$6,403,661	0.1390
1998		729,269	6,251,888	0.1166
1999	(8 months)	741,693	4,234,126	0.1752
			Average	0.1436
		Gross Annualized Payroll		$6,274,614
				$900,970

Therefore, the Company concludes that test year Medical Coverage is understated by $171,701 using the Attorney General's methodology. Only $77,561 was originally adjusted by the Company on Schedule 4, tab 25, of the Filing Requirements. Therefore, an additional adjustment of $94,100 is warranted.

<u>1.880.01 Fees Training Schools</u>

Test year expense for this account is significantly understated as well. 1997 expense was $51,436 while the first 8 months of 1999 the expense is $26,869, which annualized is $40,304. The average of 1997 and annualized 1999 is

$45,870, or $31,700 more than the test year amount of $14,173. Therefore, an additional adjustment of $31,700 is warranted.

1.900.03 Small Tools

Test year expense for this account is also understated. 1997 expense was $82,435 while the first 8 months of 1999 the expense is $43,330, which annualized is $64,995. The average of 1997 and annualized 1999 is $73,715, or $20,700 more than the test year amount of $53,056. Therefore, an additional adjustment of $20,700 is warranted.

1.926.02 Pension

This account, ironically, is one that Henkes picked out to reduce. Unfortunately, Henkes used incorrect numbers and assumptions, as specifically pointed out later in this testimony. Correcting the numbers, using the Henkes approach, would cause us to substitute actual future periodic pension expense of $267,238, add the actual amount of fees from the test year $40,354 to total $307,592 of future expense. This is $14,774 more than the test year amount. This difference, multiplied by the 73.98% factor applied by the Attorney General yields an additional adjustment of $10,930.

1.932.05 Maintenance Computer Equipment

An Itron service agreement for calendar 1998 was booked in 1997. Therefore, this account was understated by the amount of $6,600.

In summary,

Medical Plan	$ 94,100
Fees Training Schools	31,700
Small Tools	20,700
Pension	10,900
Maintenance Computer Equipment	6,600
Additional expense recommended	$164,000

Therefore, the Company maintains that if the Attorney General is successful in decreasing O&M by his proposed amounts, then his theory, applied consistently to all of the Company's accounts, would, at a minimum, require an adjustment of $164,000, as detailed above, to increase O&M expenses.

Q. DO YOU AGREE WITH THE NUMBERS USED BY HENKES IN THE PENSION EXPENSE ADJUSTMENT?

A. No. The $292,818 during the test year in account 1.926.02 not only includes net periodic pension expense, determined by the actuary, but also expenses paid to Hand and Associates (actuary), American Industry Trust Company (trustee) and the Pension Benefit Guaranty Corporation. Those expenses for the test year, completely ignored in Henkes' adjustment, were $40,354 and will likely increase in future years. Therefore, the amount during the test year booked as net periodic pension expense was $252,464, which is a blending of two fiscal years: The net periodic pension expense was $271,455 for the year ended June 30, 1998 and $181,167 for the year ended June 30, 1999, as provided in response to Supplemental AG-23.

Q. WAS HENKES CORRECT IN STATING THAT "THE COMPANY'S PENSION COSTS FOR THE NEAR-TERM FUTURE WILL CONTINUE TO GO DOWN, OR AT THE MINIMUM, WILL STAY AT APPROXIMATELY THE SAME LEVEL AS THE CURRENT ANNUALIZED PENSION COST LEVEL OF $181,000"?

A. No. The justification offered by Henkes has no merit. Delta has received the Net Pension Expense at 4/1/2000 from the actuary, and the amount is $267,237.67, or **a significant increase** from the 4/1/1999 level.

Q. DO YOU HAVE ANY COMMENT ABOUT THE COLLECTION OF ITEMS LABELED "MISCELLANEOUS EXPENSE REMOVALS" BY HENKES?

A. Yes. The majority of the $30,114 amount is $27,631 for a sales tax audit, which is an expense entirely different than the other items that Henkes has buried under the miscellaneous caption. This amount is not abnormal, just part of the regular cost of doing business. This amount in the test year relates to Kentucky sales tax, but Delta is constantly engaged in audits/reviews by various agencies and payments of settlement amounts are not unusual. Even when no amounts are required to be paid to the agency, the Company always incurs legal and accounting professional services fees. To illustrate, in the last 12 months, three of the company's employee benefit plans have been audited by the IRS, and the Company is currently undergoing an IRS Revenue Agent Review on its June 30, 1997 consolidated tax return.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In Re the Matter of:
Adjustment of Rates of Delta) 99-176
Natural Gas Company, Inc.)

MOTION FOR ENLARGEMENT OF TIME

Comes the Attorney General, by and through his Office for Rate Intervention and moves the Commission to grant a one day enlargement of time for filing and serving the copies of the responses to the Requests for Information Propounded to the Attorney General by Delta Natural Gas Company, Inc. to and including October 15, 1999 and as grounds therefore states as follows:

1. The Responses to the Requests for Information for both the Company and the Commission were given to the print shop for reproduction with the assurance they would be done in time to file and serve them by day's end. The Commission responses were completed. By day's end, the Company responses had only been scanned in to initiate the reproduction process, but the copies had not been made.

2. In order to prevent any prejudice to Delta as a result of the delay, the Attorney General's office is hand delivering the Company copies directly to Counsel and to the Company on Friday, October 15, 1999 so that the responses will be received as rapidly as they would have had they been mailed on the 14th. Staff copies will also be delivered on October 15, 1999.

Respectfully Submitted

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

CERTIFICATE OF SERVICE AND OF FILING

I hereby certify that the Original of this Motion together with the Original Responses to the Data Requests Propounded to the Attorney General by Delta Natural Gas Company, Inc. have been filed with the Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601 this the 14th day of October, 1999, and that eight copies of same will be filed with the Commission on October 15, 1999 and that copies of same will be hand delivered to the following on October 15, 1999:

JOHN F HALL
VICE PRESIDENT-FINANCE SEC TREAS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

HONORABLE ROBERT M WATT III
STOLL KEENON & PARK LLP
201 EAST MAIN STREET SUITE 1000
LEXINGTON KY 40507 1380

J.L. Blackford

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797
Phone: 606-744-6171
Fax: 606-744-3623

October 5, 1999

Hon. Helen Helton
Executive Director
Kentucky Public Service Commission
P O Box 615
Frankfort, KY 40602

RE An Adjustment of General Rates of
Delta Natural Gas Company Inc
Case No. 99-176

Dear Ms. Helton:

Pursuant to the Data Request dated July 15, 1999 in the above captioned case, attached please find the original and ten copies of the monthly update to question No. 48. We would appreciate your placing the response with the other papers in the case.

Sincerely,

John F. Hall

John F. Hall
Vice President – Finance,
Secretary & Treasurer

cc: Hon. Elizabeth E. Blackford (w/enclosure)
Robert M. Watt (w/enclosure)

SUMMARY RATE CASE EXPENSES

	CASE NO	AMOUNT
ALT REG EXPENSES	#99-046	$ 35,518.11
RATE CASE EXPENSES	#99-176	$ 100,655.07
TOTAL RATE CASE EXPENSES @ 10/04/99		$ 136,173.18

RECEIVED
OCT 0 6 1999
PUBLIC SERVICE COMMISSION

Item 48a

DELTA NATURAL GAS COMPANY, INC.
CASE #99-046
Alt Reg Case Expenses
for period ended 10/01/99

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description	Hours	Rate/Hr
11860700000000	1999-05-31	156482	3640	PRIME GROUP, THE	$2,310.00	#99-046	14.0	165
11860700000000	1999-06-30	157403	3640	PRIME GROUP, THE	$15,427.72	#99-046	101.0	153
11860700000000	1999-08-19	158773	3640	PRIME GROUP, THE	$7,375.00	#99-046	47.0	157
11860700000000	1999-09-10	159322	3640	PRIME GROUP, THE	$420.00	#99-046	3.0	140
				TOTAL CONSULTANTS	**$25,532.72**			
11860700000000	1999-05-31	156485	2334	STOLL,KEENON & PARK LLP	$863.00	#99-046	5.2	165
11860700000000	1999-06-30	157156	2334	STOLL,KEENON & PARK LLP	$2,264.36	#99-046	13.4	165
11860700000000	1999-07-22	157895	2334	STOLL,KEENON & PARK LLP	$3,307.60	#99-046	19.3	165
11860700000000	1999-08-25	158926	2334	STOLL,KEENON & PARK LLP	$914.06	#99-046	4.8	165
11860700000000	1999-09-30	AP	2334	STOLL,KEENON & PARK LLP	$642.00	#99-047	3.7	165
				TOTAL LEGAL	**$7,991.02**			
11860700000000	1999-05-31	156211	33	ADVOCATE PUBLISHING CO	$82.50	#99-046		
11860700000000	1999-05-31	156745	210	BATH CO NEWS OUTLOOK	$39.00	#99-046		
11860700000000	1999-05-31	156231	256	BEREA CITIZEN	$111.38	#99-046		
11860700000000	1999-05-31	156529	485	CENTRAL RECORD	$39.00	#99-046		
11860700000000	1999-05-31	156533	509	CITIZEN VOICE	$87.30	#99-046		
11860700000000	1999-05-31	156256	564	CLAY CITY TIMES	$87.30	#99-046		
11860700000000	1999-05-31	156597	1261	JESSAMINE JOURNAL	$56.25	#99-046		
11860700000000	1999-06-15	156608	NA	LEDGER-INDEPENDENT	$34.14	#99-046		
11860700000000	1999-05-31	156342	3319	LESLIE COUNTY NEWS	$94.50	#99-046		
11860700000000	1999-06-24	156836	1473	LEXINGTON HERALD LEADE	$262.13	#99-046		
11860700000000	1999-06-30	157800	1557	MANCHESTER ENTERPRISE	$96.05	#99-046		
11860700000000	1999-05-31	156369	1645	MIDDLESBORO DAILY NEWS	$135.20	#99-046		
11860700000000	1999-05-31	156382	1789	NEWS JOURNAL	$178.13	#99-046		
11860700000000	1999-05-31	156383	3607	NEWSPAPER HOLDINGS,INC	$249.38	#99-046		
11860700000000	1999-06-24	156869	1923	PINEVILLE SUN	$120.00	#99-046		
11860700000000	1999-05-31	156649	2069	RICHMOND REGISTER	$93.66	#99-046		
11860700000000	1999-05-31	156664	2152	SENTINEL-ECHO	$84.94	#99-046		
11860700000000	1999-05-31	156438	2409	THREE FORKS TRADITION	$63.00	#99-046		
11860700000000	1999-05-31	156176	2411	TIMES-TRIBUNE	$80.51	#99-046		
				TOTAL NEWSPAPER ADS	**$1,994.37**			

DELTA NATURAL GAS COMPANY, INC.

CASE #99-046

Alt Reg Case Expenses

for period ended 10/01/99

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description	Hours	Rate/Hr
				TOTAL SUPPLIES - OTHER	**$0.00**			
				TOTAL ALT REG #99-046 EXPENSE @ 10/01/99	**$35,518.11**			

Item 48a

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
Rate Case Expenses
for period ended 10/01/99

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description		Hours	Rate/Hr
118607000000000	1999-05-31	156482	3640	PRIME GROUP, THE	$21,220.00	CONSULTANTS	#99-176	129.5	164
118607000000000	1999-06-30	157403	3640	PRIME GROUP, THE	$24,382.72	CONSULTANTS	#99-176	148.5	164
118607000000000	1999-08-19	158773	3640	PRIME GROUP, THE	$785.00	CONSULTANTS	#99-176	5.0	157
118607000000000	1999-09-10	159322	3640	PRIME GROUP, THE	$10,540.00	CONSULTANTS	#99-176	63.5	166
118607000000000	1999-09-23	159701	3742	HISLE & COMPANY	$685.34	CONSULTANTS	#99-176	16.0	43
118607000000000	1999-09-30 AP		3640	PRIME GROUP, THE	$15,173.16	CONSULTANTS	#99-177	95.0	159
				TOTAL CONSULTANTS	**$72,786.22**				
118607000000000	1999-07-22	157895	2334	STOLL, KEENON & PARK	$825.00	LEGAL FEES	#99-176	5.0	165
118607000000000	1999-08-25	158926	2334	STOLL, KEENON & PARK	$676.32	LEGAL FEES	#99-176	3.8	165
118607000000000	1999-09-30 AP		2334	STOLL, KEENON & PARK	$1,317.57	LEGAL FEES	#99-177	7.3	165
				TOTAL LEGAL	**$2,818.89**				
118607000000000	1999-07-31	158275	33	ADVOCATE PUBLISHING CO	$724.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-18	156745	210	BATH COUNTY NEWS OUTLOOK	$425.25	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158293	256	BEREA CITIZEN	$182.25	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158312	485	CENTRAL RECORD	$270.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-02	157926	3302	CITIZEN ADVERTISER	$525.69	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158313	509	CITIZEN VOICE	$628.56	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158317	564	CLAY CITY TIMES	$628.56	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-18	157262	3335	FLEMINGSBURG GAZETTE	$157.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-18	158597	3335	FLEMINGSBURG GAZETTE	$157.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-25	158838	1242	JACKSON COUNTY SUN	$850.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158378	1261	JESSAMINE JOURNAL	$384.39	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-22	157978	3319	LESLIE COUNTY NEWS	$976.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-30	158058	1473	LEXINGTON HERALD LEADER	$1,934.49	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-30	158398	1557	MANCHESTER ENTERPRISE	$775.47	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158266	3688	MAYSVILLE NEWSPAPERS	$1,151.60	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158408	1645	MIDDLESBORO DAILY NEWS	$709.80	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157555	1645	MIDDLESBORO DAILY NEWS	$354.90	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158195	1720	MT STERLING ADVOCATE	$133.92	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157326	1789	NEWS JOURNAL	$420.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-26	157995	1789	NEWS JOURNAL	$840.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158423	1789	NEWS JOURNAL	$840.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-16	158423	1789	NEWS JOURNAL	-$840.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157573	3607	NEWSPAPER HOLDINGS INC	$406.88	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158424	3607	NEWSPAPER HOLDINGS INC	$813.76	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158432	1923	PINEVILLE SUN	$775.47	NEWSPAPERS ADS	#99-176		

Item 48a

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
Rate Case Expenses
for period ended 10/01/99

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description	Hours	Rate/Hr
118607000000000	1999-07-31	158442	2069	RICHMOND REGISTER	$722.52	NEWSPAPERS ADS #99-176		
118607000000000	1999-06-30	157603	2152	SENTINEL-ECHO, THE	$473.45	NEWSPAPERS ADS #99-176		
118607000000000	1999-07-31	158453	2152	SENTINEL-ECHO, THE	$946.90	NEWSPAPERS ADS #99-176		
118607000000000	1999-07-26	158029	2409	THREE FORKS TRADITION	$450.00	NEWSPAPERS ADS #99-176		
118607000000000	1999-06-30	157619	2411	TIMES-TRIBUNE, THE	$279.63	NEWSPAPERS ADS #99-176		
118607000000000	1999-07-31	158472	2411	TIMES-TRIBUNE, THE	$559.26	NEWSPAPERS ADS #99-176		
118607000000000	1999-06-30	157899	3148	WINCHESTER SUN, THE	$338.17	NEWSPAPERS ADS #99-176		
118607000000000	1999-07-22	157899	3148	WINCHESTER SUN, THE	$676.34	NEWSPAPERS ADS #99-176		
				TOTAL NEWSPAPER ADS	**$18,673.76**			
118607000000000	1999-06-18	156715	3334	NATIONAL CITY	$134.10	SUPPLIES #99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$508.48	SUPPLIES #99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$769.86	SUPPLIES #99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$1,619.61	SUPPLIES #99-176		
118607000000000	1999-07-31	158268	3334	NATIONAL CITY	$230.87	SUPPLIES #99-176		
118607000000000	1999-08-19	158712	3230	MARY STEELE	$850.05	SUPPLIES #99-176		
118607000000000	1999-08-31	159154	3334	NATIONAL CITY	$240.99	SUPPLIES #99-176		
118607000000000	1999-08-31	159154	3334	NATIONAL CITY	$1,072.94	SUPPLIES #99-176		
118607000000000	1999-09-17	159575	58	AMERICAN EXPRESS	$932.38	SUPPLIES #99-176		
118607000000000	1999-09-30	AP	3334	NATIONAL CITY	$16.92	SUPPLIES #99-176		
				TOTAL SUPPLIES - OTHER	**$6,376.20**			
				TOTAL RATE CASE #99-176 EXPENSE @ 10/01/99	**$100,655.07**			

STOLL, KEENON & PARK, LLP

201 EAST MAIN STREET
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LEXINGTON, KENTUCKY 40507-1380

(606) 231-3000
FAX: (606) 253-1093

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(502) 875-6220
FAX: (502) 875-6235

**WESTERN KENTUCKY OFFICE:
201 C NORTH MAIN STREET
HENDERSON, KY. 42420-3103
(502) 831-1900
FAX: (502) 827-4060

***LOUISVILLE OFFICE:
2650 AEGON CENTER
400 WEST MARKET
LOUISVILLE, KY. 40202-3377
(502) 568-9100
FAX: (502) 568-5700

INTERNET: www.skp.com

October 4, 1999

Hon. Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

Re: Delta Natural Gas Company, Inc.
Case No. No. 99-176

Dear Ms. Helton:

We deliver herewith for filing ten (10) copies of Delta's Data Requests to the Attorney General in the above-captioned case. We would appreciate your placing the Data Requests with the other papers in the case. Thank you for your kind assistance.

Sincerely,

Robert Watt

Robert M. Watt, III

rmw
encl.
cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/o encl.)

RECEIVED

OCT 0 4 1999

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF	)	
DELTA NATURAL GAS COMPANY, INC.	)	**CASE NO. 99-176**

* * * * * * * * * * *

REQUEST FOR INFORMATION PROPOUNDED TO THE ATTORNEY GENERAL BY DELTA NATURAL GAS COMPANY, INC.

Delta Natural Gas Company, Inc. ("Delta") submits this Request for Information to the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, ("Attorney General"), to be answered by the date specified in the Commission's Order of Procedure herein.

INSTRUCTIONS

1. Please identify the witness who will be prepared to answer questions concerning each request.

2. These requests shall be deemed continuing so as to require further and supplemental responses if the Attorney General receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted herein.

3. To the extent that the specific document, work paper or information as requested does not exist, but a similar document, work paper or information does exist, provide the similar document, work paper or information.

4. To the extent that any request may be answered by way of a computer printout, please

identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

5. For any document withheld on the ground of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown or explained; ant the nature and legal basis for the privilege asserted.

6. In the event any document requested has been destroyed or transferred beyond the control of the Attorney General, or any of his witnesses, state: the identity of the person by whom it was destroyed or transferred and the person authorizing the destruction or transfer; the time, place and method of destruction or transfer; and the reason(s) for its destruction or transfer. If destroyed or transferred by reason of a document retention policy, describe in detail the document retention policy.

7. If any document responsive to a request is a matter of public record, please produce a copy of the document rather than refer Delta to the record where the document is located.

INFORMATION REQUESTS

1. Please describe in detail the agreement or arrangement by which Robert J. Henkes ("Henkes") is consulting, testifying or otherwise performing services for the Attorney General in this proceeding, including, without limitation, the following information:

a. the total fees or other charges to be paid by the Attorney General to Henkes for his services in this proceeding;

b. the hourly or daily rate or amount payable to Henkes;

c. the total amount of fees or other compensation paid by the Attorney General to Henkes to date;

d. out of pocket disbursements and/or other expenses paid and payable to Henkes by the Attorney General in connection with this proceeding;

e. a description of the services to be performed by him.

2. Please describe in detail the agreement or arrangement by which Carl G. K. Weaver ("Weaver") is consulting, testifying or otherwise performing services for the Attorney General in this proceeding, including, without limitation, the following information:

a. the total fees or other charges to be paid by the Attorney General to Weaver for his services in this proceeding;

b. the hourly or daily rate or amount payable to Weaver;

c. the total amount of fees or other compensation paid by the Attorney General to Weaver to date;

d. out of pocket disbursements and/or other expenses paid and payable to Weaver by the Attorney General in connection with this proceeding;

e. a description of the services to be performed by him.

3. Please describe in detail the agreement or arrangement by which Thomas S. Catlin ("Catlin") is consulting, testifying or otherwise performing services for the Attorney General in this proceeding, including, without limitation, the following information:

a. the total fees or other charges to be paid by the Attorney General to Catlin for his services in this proceeding;

b. the hourly or daily rate or amount payable to Catlin;

c. the total amount of fees or other compensation paid by the Attorney General to Catlin to date;

d. out of pocket disbursements and/or other expenses paid and payable to Catlin by the Attorney General in connection with this proceeding;

e. a description of the services to be performed by him.

4. Please describe in detail the agreement or arrangement by which Richard A. Galligan ("Galligan") is consulting, testifying or otherwise performing services for the Attorney General in this proceeding, including, without limitation, the following information:

a. the total fees or other charges to be paid by the Attorney General to Galligan for his services in this proceeding;

b. the hourly or daily rate or amount payable to Galligan;

c. the total amount of fees or other compensation paid by the Attorney General to Galligan to date;

d. out of pocket disbursements and/or other expenses paid and payable to Galligan by the Attorney General in connection with this proceeding;

e. a description of the services to be performed by him.

5. Please describe in detail the agreement or arrangement by which Steven L. Estomin ("Estomin") is consulting, testifying or otherwise performing services for the Attorney General in this proceeding, including, without limitation, the following information:

a. the total fees or other charges to be paid by the Attorney General to Estomin for his services in this proceeding;

b. the hourly or daily rate or amount payable to Estomin;

c. the total amount of fees or other compensation paid by the Attorney General to Estomin to date;

d. out of pocket disbursements and/or other expenses paid and payable to Estomin by the Attorney General in connection with this proceeding;

e. a description of the services to be performed by him.

6. Please produce all documents containing, describing or relating to the agreements or arrangements by which Henkes, Weaver, Catlin, Galligan and Estomin are testifying, consulting or otherwise providing services to the Attorney General in connection with this proceeding.

7. Please provide a list all cases in which Galligan has testified, showing the following information:

a. Docket number and forum of the case

b. Description of the case

c. Name of utility

d. Party represented by Galligan

e. Date testimony was presented.

f. Issues addressed in Galligan's testimony

g. Date of final order in case.

8. Please provide a list all cases in which Catlin has testified, showing the following information:

a. Docket number and forum of the case

b. Description of the case

c. Name of utility

d. Party represented by Catlin

e. Date testimony was presented.

f. Issues addressed in Catlin's testimony

g. Date of final order in case.

9. Please provide Estomin's testimony in the following proceedings:

a. Before the New Mexico Public Service Commission, El Paso Electric Company, 1996, for the U.S. Air Force.

b. Before the Sacramento Municipal Utility District Board, February 1987, for the U.S. Air Force.

10. Please produce copies of all testimony, including, without limitation, direct, cross-examination, rebuttal or surrebuttal testimony, presented by Henkes, Weaver, Catlin, Galligan or Estomin, or any of them, before the Kentucky Public Service Commission within the last ten (10) years in which such persons have offered testimony on the same subjects contained in their direct testimony in this proceeding.

11. Please produce copies of all orders addressing the substantive issues, including the testimony of Henkes, Weaver, Catlin, Galligan or Estomin in each case responsive to Request No. 10.

12. Provide a copy of any and all testimony presented at any time by Catlin that involves a gas utility or a combination gas utility (e.g., gas and electric utility, gas and water utility gas, water and electric utility, etc.).

13. Provide a copy of any and all testimony presented at any time by Galligan that involves a gas utility or a combination gas utility (e.g., gas and electric utility, gas and water utility gas, water and electric utility, etc.).

14. Provide a copy of any and all testimony presented at any time by Weaver that involves

a gas utility or a combination gas utility (e.g., gas and electric utility, gas and water utility gas, water and electric utility, etc.).

15. Provide a copy of any and all testimony presented at any time by Henkes that involves a gas utility or a combination gas utility (e.g., gas and electric utility, gas and water utility or gas, water and electric utility, etc.).

16. Provide a copy of any and all testimony presented at any time by Estomin that involves a gas utility or a combination gas utility (e.g., gas and electric utility, gas and water utility or gas, water and electric utility, etc.).

17. Please provide a copy of all gas cost of service studies prepared by Catlin.

18. Please provide a copy of all gas cost of service studies prepared by Galligan.

19. Provide a copy of all electric cost of service studies prepared by Galligan.

20. Provide a copy of any and all testimony presented at any time by Catlin that deals with the allocation of costs in a rate case.

21. Provide a copy of any and all testimony presented at any time by Galligan that deals with the allocation of costs in a rate case.

22. On page 8, line 10 of his testimony filed on September 23, 1999, Weaver states that, "The use of a hypothetical capital structure is a fiction that simply does not exist." Has Weaver ever recommended the use of a hypothetical or imputed capital structure in any proceeding before any regulatory agency in order to adjust for a capital structure chosen by management? If yes, please provide copies of all testimony that includes such recommendation.

23. Does Weaver believe that low earnings *ceteris paribus* can reduce the percentage of equity of a utility's capital structure? If not, please describe in detail the basis for such response.

24. Please define the term "likelihood" as Weaver uses the term on page 3, line 3, page 3, line 17 and page 14, line 15 of his testimony submitted July 1999 in Case No. 99-046.

a. If Weaver is using the term "likelihood" in a mathematical or statistical sense, please provide the formula for determining likelihood.

b. Please explain how a change in the mean level of a variable affects likelihood.

c. Please explain how a change in the variability of a variable affects likelihood.

25. Please define the term "risk" as Weaver uses the term on page 4, line 18 of his testimony submitted July 1999 in Case No. 99-046.

a. Can risk be quantified?

b. If the response to (a) is affirmative, please provide the formula that quantifies "risk" as Weaver uses the term.

26. On page 10, lines 12 –13 of his testimony submitted July 1999 in Case No. 99-046., Weaver states that, "I measure the risk premium by subtracting the actual equity returns earned by companies that are similar to Delta from long-term Treasury bonds."

a. Would equity returns be affected by the percentage of debt in a utility's capital structure? If yes, please explain how they would be affected. If no, please explain why there would be no effect.

b. How large a difference in the equity component of the capital structure would be acceptable to still classify two utilities as "similar"?

c. Explain in detail how Delta is similar to the five companies utilized by Weaver as comparable companies in his testimony.

27. On page 11, lines 19 –20 of his testimony submitted July 1999 in Case No. 99-046,

Weaver states that, "I assessed the amount of risk reduction that would result from the implementation of the ARP… "

a. Was this assessment objective or subjective?

b. Please provide the methodology and workpapers used to assess the amount of risk reduction.

28. Please refer to page 12, line 5, of Weaver's testimony submitted in July 1999 in Case No. 99-046.

a. Describe in detail all of the characteristics of Delta which support Weavers' assertion that his panel of five companies are similar to Delta.

b. Identify each company in Weaver's panel of five companies which utilize alternative regulation plans.

c. Please state the earned returns on equity for each company in Weaver's panel of five companies for each of the last five years.

d. Identify each company in Weaver's panel of five companies which utilize weather normalization adjustments.

29. Please refer to page 12, line 16, of Weaver's testimony submitted in July 1999 in Case No. 99-046.

a. Please produce all documents containing or reflecting studies of the efficiency of the New York Stock Exchange.

b. Please produce all documents containing or reflecting studies of the efficiency of the NASDAQ system.

30. On page 13, lines 18 –20 of his testimony submitted July 1999 in Case No. 99-046,

Weaver states that, "Rural companies would typically require a higher investment in assets per customer than urban companies."

a. Please quantify "higher investment" as such term is used by Weaver in his testimony.

b. Please define the term "rural company" as such term is used by Weaver in his testimony.

c. Are any of the five companies in Weaver's panel classified as a "rural company" based on such definition. If yes, please identify which ones.

d. Please name any other natural gas distribution companies that are "rural companies," as such term is used by Weaver in his testimony?

e. Please produce all work papers, analyses or other documents which provide support for the use of the 0.70 ratio on line 20 Weaver's testimony identified above.

31. On page 14, line 7 of his testimony submitted July 1999 in Case No. 99-046, Weaver states that, "Leverage, measured by the mix of debt and equity capital, is a source of risk to companies." On page 25, lines 2-4 of his testimony, Weaver states that, "It is a little more risky from its greater use of financial leverage, its greater operating leverage and a greater need for external financing."

a. Has Weaver performed any research that quantifies the relationship between leverage and risk? If yes, please provide a copy of such research.

b. Is Weaver aware of any research that quantifies the relationship between leverage and risk? If yes, please provide citations to such research.

c. Has Weaver performed any research that quantifies the relationship between leverage and the return on equity? If yes, please provide a copy of such research.

d. Is Weaver aware of any research that quantifies the relationship between leverage and the return on equity? If yes, please provide citations to such research.

32. Please refer to page 14, line 12, of Weaver's testimony in July 1999 in Case No. 99-046. Please provide all analyses, workpapers or other documents which contain or reflect a comparison of the earnings per share of Delta on the one hand and each of the companies in Weaver's panel of five companies.

33. On page 15, line 10-11 of his testimony submitted July 1999 in Case No. 99-046, Weaver states that, "the five companies are larger than Delta and less risky, to the extent that size affects risk."

a. Has Weaver performed any research that quantifies the relationship between size and risk? If yes, please provide a copy of such research.

b. Is Weaver aware of any research that quantifies the relationship between size and risk? If yes, please provide citations to such research.

c. Has Weaver performed any research that quantifies the relationship between size and the return on equity? If yes, please provide a copy of such research.

d. Is Weaver aware of any research that quantifies the relationship between size and the return on equity? If yes, please provide citations to such research.

34. Please refer to page 15, lines 17-18, of Weaver's testimony submitted in July 1999 in Case No. 99-046. Please quantify how much greater the investments in assets to provide service of companies in rural and mountainous regions are than companies in other regions.

35. On page 16, lines 4-6 of his testimony submitted July 1999 in Case No. 99-046,

Weaver states that, "The average total liabilities to total assets ratio for Delta is also greater but on a relative basis, the five companies have a greater amount of current liabilities than Delta." Explain in detail the basis on which the current liabilities of the five companies are greater than Delta's.

36. Please refer to page 17, lines 14-16, of Weaver's testimony submitted in July 1999 in Case No. 99-046. Please provide all workpapers and other documents containing or reflecting the calculations referred to in Weaver's Schedules 8-13 to his testimony, as well as copies of the source documents and cross-references to the source documents.

37. Please refer to page 22, lines 14-15, of Weaver's testimony submitted in July 1999 in Case No. 99-046. Please provide all documents containing or reflecting Delta's beta, including workpapers, analyses and source documents with cross-references to the source documents.

38. On page 30, lines 10-14 of his testimony submitted July 1999 in Case No. 99-046, Weaver notes that Delta has experienced a large amount of variability in earnings per share during the ten year period that he examined. He goes on to note that, in spite of the EPS variability, Delta was able to maintain a relatively constant and slowly growing dividend. What was the trend in the equity component of Delta's capital structure during the same 10 year period?

39. On page 30, line 22 of his testimony submitted September 23, 1999, Weaver states that, "Delta has a larger residential and commercial load than the five companies so it would be somewhat more adversely affected by weather."

a. Would greater sensitivity to weather make Delta more or less risky than the other 5 companies in Weaver's panel?

b. Has Weaver quantified the increase or decrease in risk due to weather sensitivity? If yes, please explain the relationship between risk and weather and provide copies of all workpapers, analyses or other documents which reflects such relationship.

c. Would the Commission's use of weather normalized billing determinants in determining rates combined with Delta's greater sensitivity to weather fluctuations increase or decrease the variability of Delta's earned returns?

40. Please refer to page 31, lines 1-3, of Weaver's testimony submitted on September 23, 1999. Please provide information, including analyses, workpapers and source documents, which support the statement that "all of the companies were hurt by a warmer than usual heating season" in 1998.

a. Identify all companies hurt by a warmer than usual heating season which utilized alternative regulation plans and/or weather normalization adjustments and describe the impact on the earnings of those companies as a result of the warmer than usual heating season.

41. On page 36, lines 11-13 of his testimony submitted September 23, 1999, Weaver states that, "The risk premiums represent the difference between the total return on the common stock and the total return on 10-year government bonds for the period 1989 through 1998."

a. Why did Weaver choose to calculate risk premiums over the ten year period 1989 through 1998?

b. During the 10-year period that Weaver used to calculate the risk premiums, have there been any significant recessions or declines in real GDP in the United States?

c. Does the 10-year period that Weaver used to calculate the risk premiums represent a full business cycle in the United States, multiple business cycles, or a partial business cycle? (A full business cycle is defined as a peak of economic activity through a trough and back to a peak again).

d. Has Weaver calculated the risk premiums over a longer period than 10 years in any other proceeding in which he has testified? If yes, please provide a copy of the testimony.

e. Has Weaver ever conducted research on risk premiums? If yes, please provide copies of the research results.

42. Please refer to page 38, line 16, of Weaver's testimony submitted on September 23, 1999. Please provide the basis for Weaver's suggested increase of 50 basis points in the cost of equity to reflect risk as opposed to 100 basis points or 200 basis points.

43. On page 38, lines 21-22 of his testimony submitted September 23, 1999, Weaver states that, "The adoption of the ARP, even on a three-year experimental basis, will considerably lower investor's risk expectations regarding Delta." Please provide copies of any studies conducted by Weaver to quantify the decline in investor's risk expectations.

44. On page 8 of Appendix II of his testimony submitted July 1999 in Case No. 99-046, Weaver argues that, " A rational investor would choose to invest in the stock that has the highest expected return in the first sub-interval, and then he would reevaluate the investment alternative prior to the start of the second interval." On page 42 lines 4-6 of his testimony submitted on September 23, 1999, Weaver states that, "It not certain at this time what modifications might need to be made to the ARP if it is approved in its present form. There could be changes that need to be made to prevent over- or under- earning." Please explain in detail how this view of rational investor behavior and the potential for over- or under-earning are consistent with Weaver's statement that the adoption of the ARP "will considerably lower investor's risk expectations regarding Delta" even on a three-

year experimental basis.

45. Please provide a summary description (containing all material components) of the performance-based rate making mechanism filed by Kentucky Utilities Company ("KU") and Louisville Gas & Electric Company ("LG&E") and supported by the Attorney General's Office in Case Nos. 98-426 and 98-474.

46. On page 10 of his testimony submitted July 1999 in Case No. 99-046, Catlin states as follows: "Over the five fiscal years from 1993 through 1998, Delta's non-gas O&M costs have increased at an annual rate of 2.28 percent. Over the same time period, inflation as measured by the CPI-U has averaged a higher 2.44 percent year. More importantly, non-gas costs as measured on a per customer basis have declined at the rate of 0.48 percent per year over the same time period." Concerning this portion of Catlin's testimony, please provide all worksheets, analyses and other documents showing how each numeric value (namely, "2.28", "2.44" and "0.48") is calculated.

47. On page 21 of his testimony submitted July 1999 in Case No. 99-046, Henkes states as follows:

> Specifically, the costs subject to the PBR mechanisms of Columbia Gas, Western Kentucky Gas and LG&E involve gas commodity, pipeline transportation, and/or gas storage costs and off-system sales, all of which elements flow through the GCRs of these utilities. For each of these gas cost/off-system sales elements, the utilities proposed market-based or other hard-to-achieve benchmarks to which their actual gas costs/off-system sales would then be compared. Generally, if the actual gas costs come in lower than these tough benchmarks, there would be a reward (for example, in the form of a 50/50 sharing of the cost savings) and if the actual gas costs are higher than the performance benchmarks, there would be a penalty (for example, by not being allowed to recovery a portion of the actual costs).

a. Provide a copy of all information concerning the PBR mechanisms of

Columbia Gas, Western Kentucky Gas and LG&E that Henkes reviewed in order to draw the conclusions expressed in this portion of his testimony (include all Commission orders and documents filed by the three utilities)

b. Please define "hard to achieve benchmarks" and "tough benchmarks" as used by Henkes in the foregoing testimony.

c. What objective standard would Henkes use to quantify whether a benchmark is "hard to achieve" or is "tough?"

d. Please describe in detail the benchmarks which are used in the PBR mechanisms of Columbia Gas, Western Kentucky Gas and LG&E.

e. Do these mechanisms compare each utility's current performance with past performance?

f. Are the PBR mechanisms of Columbia Gas, Western Kentucky Gas and LG&E designed to "to reward performance which is better than has been historically been achieved without the performance mechanism in place (or penalize performance which is worse than historically achieve)?" Please explain.

g. Did Henkes determine how well Columbia Gas, Western Kentucky Gas and LG&E's gas supply costs performed in relation to the benchmarks utilized by these companies during the 5-year period, or for any period, prior to the implementation of each utility's mechanism?

48. With respect to the PBR mechanism filed by LG&E in Case No. 98-426 and KU in Case No. 98-474 and supported by the Attorney General, does this mechanism include "hard to achieve" or "tough" benchmarks? If so, please identify each such benchmark and explain the basis

for the conclusion that each such benchmark is "hard to achieve" or tough."

49. On page 24 of his testimony submitted July 1999 in Case No. 99-046, Henkes states that "the three PBRs are fairly simple to understand, implement and administer, with little opportunity for disputes and "gaming," whereas Delta's ARP is complicated, cumbersome to implement and administer, with opportunities for disputes and "gaming."

a. Please define the expression "simple to understand?"

b. How is the concept "simple to understand" measured?

c. Please define the term "complicated?"

d. How is the concept "complicated" measured?

e. How many calculations (i.e., mathematical operations such as addition, subtraction, multiplication, division) must be performed by LG&E in the PBR filing reviewed by Henkes?

f. How many calculations (i.e., mathematical operations such as addition, subtraction, multiplication, division) must be performed by Western Kentucky Gas in the PBR filing reviewed by Henkes?

g. How many calculations (i.e., mathematical operations such as addition, subtraction, multiplication, division) must be performed by Columbia in the PBR filing reviewed by Henkes?

h. How many calculations (i.e., mathematical operations such as addition, subtraction, multiplication, division) must be performed by KU and LG&E in their periodic filings under the PBR mechanisms submitted in Case Nos. 98-426 and 98-474?

50. On page 11 of his testimony submitted July 1999 in Case No. 99-046, Catlin states

that "CPI-U is heavily weighted toward consumer items, such as food/beverages, housing, apparel, transportation and recreation"

a. What is the basis of Catlin's statement?

b. What "weight" is given to consumer items such as food/beverages, housing, apparel, transportation and recreation in the determination of the CPI-U?

c. What "weight" is given to consumer items such as food/beverages, housing, apparel, transportation and recreation in the determination of Gross Domestic Product-Price Index (GDP-PI)?

51. Please provide the following information concerning the Gross Domestic Product-Price Index (GDP-PI):

a. Please provide the monthly values of the index for the past 20 years.

b. Please provide a full description of the index.

c. Please provide all empirical evidence that supports Catlin's statement that GDP-PI is likely to be more representative of the price increases which Delta experiences than the CPI-U.

d. Please provide copies of economic journal articles or other authoritative texts that support Catlin's conclusion that GDP-PI is more representative of the price increases that a utility experiences than CPI-U.

e. Please provide copies of economic journal articles or other authoritative texts that support Catlin's conclusion that GDP-PI represents a broader measure of inflation than CPI-U.

52. On page 11 of his testimony submitted July 1999 in Case No. 99-046, Catlin states

that "non-gas O&M expenses are, for the most part, not customer sensitive." Please provide empirical evidence in support of this statement.

53. On page 11 of his testimony submitted July 1999 in Case No. 99-046, Catlin states that Delta "is likely to be realizing productivity gains."

a. Please define the term "productivity gains."

b. Please explain why Delta is likely to be realizing productivity gains and quantify such gains.

54. See pages 6 and 7 of Catlin's testimony. "As a general matter, a rate mechanism which allows a utility to more or less automatically increase rates to recover cost increases will result in a reduction in the incentive for the utility to control costs. This is especially true for the ARP proposed by Delta."

a. Please explain in detail how the mechanism allows Delta to "....... more or less automatically increase rates to recover cost increases ......"

b. Please provide any analyses or other supporting data that support the statement that such a mechanism, with Commission oversight, "will result in a reduction in the incentive for the utility to control costs".

55. Please refer to page 7 of Catlin's testimony submitted July 1999 in Case No. 99-046. "... the Company's proposed procedure provides guaranteed recovery of the Company's costs." Identify in detail each and every cost to which Catlin refers in such testimony.

56. See page 10 of Catlin's testimony submitted July 1999 in Case No. 99-046. " ... the Company's proposed O&M mechanism is not likely to impose any real limitation on the increases in O&M costs which can be passed through to ratepayers."

a. Is this conclusion based on the 1993 through 1998 analysis that the Attorney General requested Delta to provide in response to Item No. 59 of the June 4, 1999, data request in Case No. 99-046? If not, please provide all studies and analysis performed by Catlin, along with a detailed description, which support this conclusion.

b. Does Catlin agree or disagree that Delta's proposal provides for the non-gas O&M expenses per customer used to compute the return on common equity to be based on the O&M expenses approved by the Commission in Delta's most recent adjustment of general rates, as adjusted for the CPI-U plus or minus 1.50%? If Catlin agrees, please explain in detail how a meaningful conclusion can be reached by comparing the results of an analysis based on unadjusted O&M data (1993 through 1998) to the performance-based O&M cost controls proposed by Delta. If Catlin disagrees, please provide any studies or analyses which support such position.

57. See page 11 of Catlin's testimony submitted July 1999 in Case No. 99-046. Please provide all studies and analyses performed by Catlin, along with a detailed description, that support his position that CDP-PI "... is more representative of the price increases which Delta experiences than the CPI-U".

58. Does Catlin agree or disagree that the Alabama mechanism uses the CPI-U, not the CDP-PI, to calculate the O&M cost constraints? Please provide any studies or analysis performed or examined by Catlin, along with a detailed description, which demonstrate that the CDP-PI is the appropriate measure for Delta and the CPI-U is the appropriate measure for Alabama Gas. If no studies or analyses have been performed or examined, please provide an explanation of why the measures should be different for Delta.

59. See page 12 of Catlin's testimony submitted July 1999 in Case No. 99-046. "... the Company could perform much worse than it has historically and still realize additional profits under its proposed mechanism. For example, over the five-year period from 1993 through 1998, Delta's non-gas O&M cost per customer changed at a rate 2.92 percent less than the rate of inflation..." Please provide any analysis performed by Catlin that shows the percentage change in Delta's non-gas O&M cost per customer using the approved O&M expenses per customer approved by the Commission in Delta's last rate case.

60. See page 16 of Catlin's testimony submitted July 1999 in Case No. 99-046. Does Catlin agree or disagree that a properly designed Alt Reg Mechanism and a properly designed Weather Normalization Adjustment (WNA) clause can operate concurrently? If Catlin disagrees, please provide all studies and analyses performed by Catlin, along with a detailed description, that supports his position.

61. See page 17 of Catlin's testimony submitted July 1999 in Case No. 99-046. Is it Catlin's position that Delta has proposed a Weather Normalization Adjustment that provides for rate adjustments in "succeeding periods" to track deficient or excess revenues resulting from departures from normal temperatures? If so, please state the basis for such conclusion.

62. Please provide copies of any statistical or other literature that would indicate that weighted least squares is based on the minimization of the following function, as shown on page 5, line 6, of Estomin's testimony:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

63. Please provide all analysis supporting the statement on page 5 of Estomin's testimony

that "[t]here is no evidence of heteroscedasticity with the subject equation."

64. Explain why it is appropriate to optimize the following weighted least squares function when heteroscedasticity is present:

$$\sum w_i \ (Y_i - (a + bX_i))^2$$

and the following weighted least squares function otherwise:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

65. Provide a theoretical explanation for using a w^2 (instead of w) in the following weighted least squares function:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

66. SPSS and SAS automatically optimize the following weighted least squares function to perform weighted least squares:

$$\sum w_i \ (Y_i - (a + bX_i))^2$$

Is Estomin aware of any statistical package that automatically uses the following function to perform weighted least squares regression:

$$\sum w_i^2 (Y_i - (a + bX_i))^2$$

If so, please provide the name of the statistical package and documentation showing that the statistical package uses Estomin's form of the function.

67. Prior to this proceeding, has Estomin ever prepared a utility cost of service study? If so, please provide a copy of all such studies.

68. Prior to this proceeding, has Estomin ever performed a zero intercept analysis as a part of a professional study? If so, please provide a copy of all such analyses.

69. Prior to this proceeding, has Estomin ever performed a weighted least squares analysis as a part of a professional study? If so, please provide a copy of all such studies.

70. Is it Estomin's position that a simple linear regression is preferable to a weighted regression analysis? If so, how does Estomin reconcile the failure of a simple regression to fully recognize all the costs and feet of pipe in determining the zero intercept as well as the variable cost?

71. Please identify the cases and provide copies of the orders where the Commission has subsequently rejected the zero intercept methodology utilized by Delta in this proceeding and substituted either the methodology proposed by Estomin or a similar methodology in its place.

72. Please provide a copies of any cost of service studies that utilize the weighted least squares methodology performed by Estomin.

73. Please provide copies of any commission orders that support the weighted least squares approach utilized by Estomin.

74. On page 5 of his testimony submitted September 23, 1999, Henkes states that ".... Delta's has negative annual revenue requirement of $(136,875), indicating the need for an annual rate decrease by that amount." How does Henkes define "annual revenue requirement? "

75. On page 7 of his testimony submitted September 23, 1999, Henkes recommends "..... that an appropriate uncollectible expense ratio be built into the revenue conversion factor." Does Henkes' recommendation hold for both revenue increases and revenue decreases?

76. On page 10 of his testimony submitted September 23, 1999, Henkes states that: "Generally, a utility's return requirement is determined by applying the calculated overall rate of return to the rate base investment, not the capital structure amount."

a. By the term "generally," does Henkes mean more than 50%? If so, provide any analysis conducted by Henkes to support this assertion.

b. Does Henkes' statement apply to orders issued by the Kentucky Public Service Commission? If so, please identify each such order.

77. On page 21 of his testimony submitted September 23, 1999, Henkes states that Delta confirmed that the revenue adjustment to reflect year-end over average customers should be increased by $119,549. However, on page 22, he indicates that Delta's proposed incremental O&M expense adjustment to reflect year-end over average customers is $54,498. Would Henkes agree that, with the correction to the revenue adjustment acknowledged by Delta, Delta's **proposed** incremental O&M expense adjustment becomes $75,906 rather than $54,498? If Henkes disagrees, please explain his disagreement and provide workpapers, analyses and other documents relating to such adjustment.

78. Has the methodology proposed by Henkes in this proceeding for calculating the expense-to-revenue ratio applicable to the adjustment to reflect year-end over average customers been recognized by the Kentucky Commission as superior for purposes of rate making prior to Delta's filing this case? If so, please cite the cases and provide the Commission orders.

79. For the expenses removed by Henkes in calculating his expense-to-revenue ratio applicable to the adjustment to reflect year-end customers (RJH-8), please provide studies performed by Henkes demonstrating that no incremental costs are incurred in these expense categories by a

utility irrespective of the number of new customers added to the system.

80. Assume that the number of customers served by a gas distribution company were to double, is it Henkes' position that Delta should be able to serve the additional customers with no change in the number of employees and should incur no cost increases in the expense items that were removed by Henkes when calculating his expense-to-revenue ratio?

81. Please refer to page 30 of Henkes' testimony submitted September 23, 1999. Has Henkes performed any studies of bad debt expense levels of companies comparable to Delta. If so, please provides copies of all documents containing or reflecting such studies.

82. Please explain how the cost of service methodology and the proposed rate design set forth in Galligan's testimony would benefit large commercial and/or industrial consumers.

83. Galligan submitted a single-page exhibit (RAG-1) which he states is the cost of service study that he has performed on the Delta system. Please provide a complete cost of service study along with the supporting workpapers showing the entire step-by-step process of assigning each item of cost to the respective rate classes set forth in Exhibit RAG-1. In addition, please provide a detailed explanation of the methodology used and underlying rationale for each cost assignment.

84. Galligan indicates at page 15 of his testimony that he allocated 50% of mains investment on the basis of average demand and 50% based on the excess of peak demand requirements over the average.

a. Please provide the complete analysis along with a detailed description which supports the 50-50 split of mains investment applicable to Delta's system.

b. Did Galligan use similar splits for other items of cost in his cost of service study? If so, please indicate what items, how each was split, the basis for assigning such costs to the rate classes and the analysis showing how such is more appropriate for Delta's system than the methodology filed by Delta.

c. Please identify all cases in which the Kentucky Commission has adopted the use of a 50-50 split of mains investment for application in a cost of service study connected with a general rate proceeding.

85. Does Galligan agree or disagree that mains serve essentially the same function in the gas distribution business as electric distribution conductor in the electric business? If Galligan disagrees, please explain in detail the basis for such disagreement.

86. Please provide copies of orders where the Commission has accepted a cost of service study that either utilizes the methodology proposed by Galligan in this case or a similar methodology.

87. Please refer to page 7 of Galligan's testimony. Is it Galligan's position that, because 807 KAR 5:022, Section 9 of the Commission Regulations specifies that a utility must extend its mains up to 100 feet to serve a new customer, this supports his position that no mains investment should be classified as customer-related? Please explain in detail.

88. Please refer to page 7, line 12 of Galligan's testimony. Please provide the basis for the statement that Delta will routinely provide 200 feet of new gas main.

89. Does Galligan agree or disagree that when a utility extends it gas mains to serve new customers, aside from determining the length of the extension in order to connect all the customers, the pipe sizing is based on the maximum loads expected to be placed on the extension? If Galligan disagrees, please explain.

90. Does Galligan agree or disagree that the length of the extension is determined by the number of customers and the distance between each customer and the size of the pipe is determined by the maximum load requirement? If Galligan disagrees, please explain.

91. On page 12 of his testimony, Galligan indicates that many costs associated with the distribution delivery system **do not** depend upon pipe size. He then identifies the following costs: surveying, excavating, hauling, pipe bed preparation, unloading and stringing pipe, municipal inspection, backfill, and pavement and sidewalk replacement. In this regard, please provide:

a. Any studies or analyses that indicate that small diameter, say rolls of 2" plastic pipe, is as expensive as large diameter, say 12", pipe to haul per foot.

b. Any studies or analyses that indicate that the excavation associated with installing small diameter, say rolls of 2" plastic, pipe is as expensive as large diameter, say 12", pipe.

c. Any studies or analyses that indicate that the pipe bed preparation associated with installing small diameter, say rolls of 2" plastic, pipe is as expensive as large diameter, say 12", pipe.

d. Any studies or analyses that indicate that small diameter, say rolls of 2" plastic, pipe is as expensive as large diameter, say 12", pipe to unload or string.

e. Any studies or analyses that indicate that the backfilling associated with installing small diameter, say rolls of 2" plastic, pipe is as expensive as large diameter, say 12", pipe.

f. Any studies or analyses that indicate that the pavement and sidewalk replacement associated with installing small diameter, say rolls of 2" plastic, pipe is as expensive as large diameter, say 12", pipe.

92. Galligan indicates on page 12, line 16, of his testimony that the additional costs associated with elevated demands is generally limited to the cost of the pipe itself. In this regard, please provide the analysis and explanation of the study performed by Galligan for Delta's system that supports this statement. If Galligan has not performed such an analysis for the Delta's system, please provide studies that he has performed for other systems, along with explanations of the studies.

93. Galligan indicates on page 12, line 17, of his testimony that pipe costs typically comprise only a small percentage of total mains installation cost. In this regard, please provide any analysis and explanation of any study performed by Galligan that supports the validity of this statement for Delta's system or the system of other comparable natural gas distributors.

94. Please refer to Table 2 on page 17 of Galligan's testimony. Please provide all supporting analyses, workpapers, calculations, assumptions and description, thereof, showing how Galligan arrived at the rates of return shown in Table 2.

95. Please refer to Table 4 on page 23 of Galligan's testimony. Please provide all supporting analyses, workpapers, calculations, assumptions and description, showing how Galligan arrived at the proposed increases for each class shown in Table 4.

96. On page 26 of his testimony submitted September 23, 1999, Henkes states that while the "adjusted 401(k) cost amount would still represent an increase of 15.4% over the prior year's expense level, it is more in line with the historical expense increase trend."

a. Quantitatively, what is the historical expense increase trend?

b. Please provide all workpapers containing Henkes' calculations of the historical expenses increase trend.

c. Please describe in detail how Henkes determined the historical expense increase trend.

97. Please provide a diskette containing Supporting Schedules RJH-1 through RJH-18 in Excel format.

98. Please admit or deny that Galligan's cost of service study did not reflect the adjustments proposed by Henkes. If the answer is anything but an unqualified admission, please provide an explanation of the answer.

99. Is it the position of the Attorney General that the utility's capital structure is always equal to or lower than its rate base?

100. Identify by name of company, date of issuance, kind of security, dollar amount involved and name of lead underwriter all issuances of equity securities during the last five years which did not have flotation costs associated therewith.

101. With reference to the Attorney General's Data Request No. 60 submitted on June 4, 1999, in Case No. 99-046,

a. Admit or deny that traditional regulation, as that term is used in Data Request No. 60, is the best method for the setting of rates consistent with regulatory practice in Kentucky.

b. If the answer to (a) is anything but an unqualified denial, please provide an explanation of why traditional regulation is the best method of regulation as applied to the determination of Delta's rates along with all evidence and numerical proof that traditional regulation is the best method for the setting of Delta's rates.

STOLL, KEENON & PARK, LLP

By Robert Watt

Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, KY 40507
606-231-3000

Counsel for Delta Natural Gas Company, Inc.

CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by mailing a copy of same, postage prepaid, to the following person on this 4th day of October 1999:

Elizabeth E. Blackford, Esq.
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601-8204

Robert Watt

Robert M. Watt, III

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

October 4, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,
Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

ORDER

IT IS ORDERED that the Attorney General ("AG") shall file the original and 8 copies of the following information with the Commission no later than October 14, 1999, with a copy to all parties of record. Each copy of the information requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure its legibility. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this Order.

1. What utilities, if any, to which Carl G.K. Weaver refers in his testimony have a Weather Normalization Adjustment ("WNA") mechanism?

2. Refer to Testimony of Thomas S. Caitlin (July 1999) at 15 - 18.

a. At page 16 of his testimony, Mr. Caitlin refers to Delta Natural Gas Company, Inc.'s ("Delta's") WNA proposal in Case No. 99-070. Did he intend to refer to Case No. 99-176 instead?

b. For each issue listed below, state whether Mr. Caitlin believes that Delta has in this proceeding adequately addressed the issue as it relates to Delta's proposed WNA mechanism and the reasons for his position:

(1) The definition of normal weather;

(2) The determination of weather-related gas usage;

(3) The consistency of normal weather used in base rate determinations and in the WNA clause;

(4) The consistency of normal weather determinations over time; and,

(5) The statistical and methodological bases of making these various determinations.

3. Provide gas distribution utilities' tariffs containing WNA mechanisms that, in Mr. Caitlin's opinion, adequately address the issues listed in Item 2(b) and are appropriate as a model for WNA mechanisms for gas distribution utilities under the Commission's jurisdiction.

4. Refer to Testimony of Carl G.K. Weaver (September 23, 1999) at 37, line 15. Should the range be "9.92 percent to 10.92 percent" instead of "9.92 percent to 10.82 percent"?

5. Refer to Testimony of Carl G.K. Weaver (September 23, 1999) at 5, lines 10 - 18.

a. When updating his testimony of July 30, 1999, why did Dr. Weaver narrow the range by striking the high-low values when he did not take this action when preparing his testimony of July 30, 1999?

b. Provide the average of the three methods if the high-low values are not excluded.

6. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 38. Show the calculations to support Dr. Weaver's statement that "[t]he cost of equity for the five companies would average from 9.75 to 10.75 percent."

7. Refer to Testimony of Carl G.K. Weaver (September 23, 1999), Schedule 34. Explain how the short-term and long-term debt cost rates were derived. Show all calculations and state all assumptions used to derive these rates.

8. Refer to Testimony of Carl G.K. Weaver (September 23, 1999) at 2, lines 5 - 10. Does Dr. Weaver consider Delta's capital structure to be high risk? Explain.

9. Refer to Testimony of Carl G.K. Weaver (September 23, 1999) at 2, lines 13 – 16, and Testimony of Carl G.K. Weaver (July 30, 1999) at 8, lines 10 - 14. Dr. Weaver's positions on the use of a hypothetical capital structure appear to conflict. Clarify Dr. Weaver's position on the use of a hypothetical capital structure.

10. In his testimony of September 23, 1999, Dr. Weaver did not amend Schedule 5, but did amend Schedule 1 to show that Delta's increase in total assets from 1997 to 1998 is 6.4 percent instead of 3.1 percent. What effect, if any, does this amendment have on page 15, lines 13 through 15, of Dr. Weaver's testimony of July 30, 1999?

11. Refer to Testimony of Carl G.K. Weaver (July 30, 1999), Schedule 5. In light of the amendment that Dr. Weaver has made to Schedule 1 of his testimony and its effect on Schedule 5 and considering the disparity between the five selected

companies' data and that of Delta, are the companies listed in Schedule 5 comparable to Delta or simply the closest relative to all 23 Value Line companies? Explain.

12. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 16, lines 2 – 7. How much of Delta's relatively greater financial risk is mitigated by its lesser amount of current liabilities?

13. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 17, line 2. Based upon the information in Schedule 7, should Delta's fixed capital service payment financing be set out as 65.4 percent instead of 64.4 percent?

14. Refer to Testimony of Carl G.K. Weaver (September 23, 1999), Schedule 15, and Testimony of Carl G.K. Weaver (July 30, 1999), Schedule 16. Considering the disparity in Beta estimates between Standard & Poor's and Value Line, could Delta be considered as having higher systematic risk by a rating agency other than Standard & Poor's? Explain the answer thoroughly.

15. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 30. Dr. Weaver indicates that the majority of Delta's Earnings Per Share ("EPS") fluctuations are weather related. To what causes does he attribute the remainder of the EPS fluctuations?

16. a. Provide a comparison of the residential and commercial load of each of the five comparable companies and Delta.

b. Provide all Value Line and Standard & Poor's reports that discuss the effect of warmer weather on each of the five comparable companies. If such reports are unavailable, provide data showing the effect of such weather on each company's EPS.

17. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 30, lines 9 - 14. During the period from 1989 to 1998, did other natural gas utilities experience a large amount of variability in EPS and yet maintain a relatively constant and slowly growing dividend? Explain.

18. Provide all source documents used for all calculations made to analyze Delta's cost of equity.

19. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 31. If I/B/E/S has updated its EPS forecast for Delta since May 1999, provide the updated forecast.

20. a. Does I/B/E/S forecast Dividends per Share ("DPS") and Book Value per Share ("BVS") growth?

b. If yes, provide I/B/E/S's most current forecasts of DPS and BVS growth for Delta and each of the five comparable companies.

21. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 40. Explain how the Alternative Rate Plan would reduce or eliminate the following:

a. Competition with alternative sources of energy;

b. Uncertainty in recovery of gas cost;

c. Volatility in the price of natural gas.

22. Refer to Testimony of Carl G.K. Weaver (July 30, 1999) at 44. Why does Dr. Weaver use the "Yield to Maturity" method in calculating the cost of long-term debt?

23. At pages 12 through 18 of his testimony of July 30, 1999, Robert J. Henkes challenges Delta's claim "that the alternative rate mechanism . . . would be less resource intensive and costly than a full-blown rate case" and asserts that the filing

costs and oversight costs for alternative regulation will result in costs equivalent to or greater than that from traditional regulation.

a. Identify each administrative proceeding involving alternative rate regulation in which Mr. Henkes was involved, Mr. Henkes' role in such proceeding, and the party for whom Mr. Henkes was employed.

b. For each proceeding identified in Item 21(a), describe the costs of such proceeding and how such costs compared with traditional rate-making proceedings.

c. Identify all studies of which Mr. Henkes is aware that have reviewed or considered the cost of alternative rate regulation proceedings as compared to traditional rate-making proceedings. Provide a copy of each study listed.

24. Refer to Testimony of Robert J. Henkes (July 30, 1999) at 20, lines 4 through 6. What modifications are necessary to Delta's proposed alternative regulation plan ("ARP") to provide "clear and quantifiable incremental" ratepayer benefits? For each proposed modification, provide a detailed description and, if the proposed modification is part of an ARP approved by a utility regulatory commission, identify the proceeding in which that ARP was approved.

25. Refer to Testimony of Richard A. Galligan at 17. Table 2 reflects the class rates of returns based upon Delta's cost-of-service study and the class rates of return as modified by the AG's cost-of-service witnesses based on actual rates. Provide a comparable table based upon the proposed rates for service.

26. The AG's cost-of-service witnesses propose modifications to Delta's cost-of-service model.

a. Provide in a format similar to Seelye Exhibit 5 the rate structure results for each class of service when this modified cost-of-service model is used.

b. For each modification proposed by the AG's cost-of-service witnesses, show all calculations, state all assumptions upon which the modification is based, and provide all documents that support the proposed modification.

27. The AG advocates an across-the-board increase for all classes of service. What class rates of return are produced using this approach?

28. On page 19 of his Direct Testimony, Mr. Henkes states that, "if the company didn't have the cumulative customer deposit balances available as a continuous source of funds, it would have to borrow short term debt at a similar interest rate." Provide any evidence the AG has to show that Delta is using its customer deposit balances to reduce its short-term borrowings.

29. a. On page 20 of his Direct Testimony, Mr. Henkes states that, "the PSC has always treated customer deposit balances as rate base deductions while treating the associated interest expenses as a pro forma operating expense in all prior Kentucky Power Company rate cases." Is the AG aware of any other rate case proceedings where the Commission has reduced rate base by the customer deposit balance while including the associated interest expense in the operating expenses?

b. Describe how the issue of customer deposits (balances and interest) was treated in Kentucky-American Water Company's prior rate case.

30. In this proceeding the AG has proposed to reduce Delta's rate base by the customer deposit balance. Would the more appropriate treatment be to include the

customer deposit balance as a source of cost free capital in Delta's capital structure? If no, provide a detailed explanation.

31. Explain if it is in the best interest of Delta's customers to permit Delta's recovery of the Canada Mountain storage field assets ("Canada Mountain") costs through Delta's gas cost recovery ("GCR") rather than through general rates.

32. How would the recovery of Canada Mountain through Delta's base rates rather than through the GCR impact the revenue requirement proposed by the AG?

33. Explain how Delta's acquisition of the assets of the Mt. Olivet Natural Gas Company would impact the AG's recommended revenue requirement.

34. On page 29 of his Direct Testimony, Robert J. Henkes states that, "amortization is designed to make the Company 'whole' for expense amounts actually incurred for a particular event." Since the cost of a rate case is incurred for a particular event, explain why normalization should be used rather than amortization.

35. Would eliminating the amortization expense of Delta's prior rate case be disallowing the recovery of a legitimate operating expense?

36. Is the AG aware of any other jurisdiction that uses the normalization methodology for the recovery of rate case expense? If yes, provide a listing of the jurisdictions and a copy of a recent decision describing the use of the normalization methodology for rate case expense.

Done at Frankfort, Kentucky, this 4th day of October, 1999.

By the Commission

ATTEST:

Helen C Helton

Executive Director

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
SEP 28 1999
PUBLIC SERVICE COMMISSION

In the Matter of:

An Adjustment of Rates of	)	Case No. 99-176
Delta Natural Gas Company, Inc.	)	

CERTIFICATE OF SERVICE AND OF FILING

I hereby certify that this the 28th day of September, 1999, I have filed the original and ten true copies of the attached errata sheet with the Kentucky Public Service Commission at 730 Schenkel Lane, Frankfort, Kentucky, 40601, and that I have mailed true copies of same, postage prepaid, to the following:

JOHN F HALL
VICE PRESIDENT-FINANCE SEC TREAS
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

HONORABLE ROBERT M WATT III
STOLL KEENON & PARK LLP
201 EAST MAIN STREET SUITE 1000
LEXINGTON KY 40507 1380

[signature]

ERRATA SHEET

Comes Robert J. Henkes and makes the following corrections to his testimony:

1. On the title page, the word "OT" should be replaced with "OF".
2. On page 8, line 13 of the testimony, the word "increase" should be replaced with "adjust".
3. On page 17, line 3 of the testimony, the word "has" should be replaced with "had".
4. On page 21, line 1 of the testimony, the initial "C" should be replaced with "D."
5. On page 24, line 16 of the testimony, the words "in this time" should be replaced with "of this case".
6. On page 29, line 5 of the testimony, the word "contract" should be replaced with "contrast".
7. On page 34, line 3 of the testimony, the word "to" should be added following the word "amount".

Done this the 27th day of September, 1999

Robert J. Henkes

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

September 14, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie D. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

STOLL, KEENON & PARK, LLP

RECEIVED

SEP 1 3 1999

PUBLIC SERVICE COMMISSION

201 EAST MAIN STREET
SUITE 1000
LEXINGTON, KENTUCKY 40507-1380

(606) 231-3000
FAX: (606) 253-1093

*FRANKFORT OFFICE:
307 WASHINGTON STREET
FRANKFORT, KY. 40601-1823
(502) 875-6220
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**WESTERN KENTUCKY OFFICE:
201 C NORTH MAIN STREET
HENDERSON, KY. 42420-3103
(502) 831-1900
FAX: (502) 827-4060

***LOUISVILLE OFFICE:
2650 AEGON CENTER
400 WEST MARKET
LOUISVILLE, KY. 40202-3377
(502) 568-9100
FAX: (502) 568-5700

INTERNET: www.skp.com

September 13, 1999

Hon. Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

RECEIVED
SEP 1 3 1999
PUBLIC SERVICE COMMISSION

Re: Delta Natural Gas Company, Inc.
Case No. No. 99-176

Dear Ms. Helton:

We deliver herewith for filing thirteen (13) copies of Delta's Responses to the Supplemental Data Requests of the Commission and the Attorney General dated September 2 and 3, 1999, respectively in the above-captioned case. We would appreciate your placing the Responses with the other papers in the case. Thank you for your kind assistance.

Sincerely,

Robert Watt

Robert M. Watt, III

rmw
encl.
cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/o encl.)

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391-9797
Phone: 606-744-6171
Fax: 606-744-3623

September 1, 1999

RECEIVED
SEP 07 1999
PUBLIC SERVICE
COMMISSION

Hon. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
P. O. Box 615
Frankfort, KY 40602

Re: An Adjustment of General Rates
of Delta Natural Gas Co., Inc.
Case No. 99-176

Dear Ms. Helton:

Pursuant to the Data Request dated July 15, 1999 in the above captioned case, attached please find the original and ten (10) copies of the monthly update to question No. 48. We would appreciate your placing the response with the other papers in the case.

Sincerely,

John F. Hall

John F. Hall
Vice President - Finance,
Secretary & Treasurer

cc: Hon. Elizabeth E. Blackford (w/ enclosure)
Robert M. Watt III (w/ enclosure)

RECEIVED
SEP 07 1999
PUBLIC SERVICE COMMISSION

Item 48a

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
Rate Case Expenses
for period ended 8/31/99

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description		Hours	Rate/Hr
118607000000000	1999-05-31	156482	3640	PRIME GROUP, THE	$21,220.00	CONSULTANTS	#99-176	129.5	164
118607000000000	1999-06-30	157403	3640	PRIME GROUP, THE	$24,382.72	CONSULTANTS	#99-176	148.5	164
118607000000000	1999-08-19	158773	3640	PRIME GROUP, THE	$785.00	CONSULTANTS	#99-176	5.0	157
				TOTAL CONSULTANTS	**$46,387.72**				
118607000000000	1999-07-22	157895	2334	STOLL, KEENON & PARK	$825.00	LEGAL FEES	#99-176	5.0	165
118607000000000	1999-08-25	158926	2334	STOLL, KEENON & PARK	$676.32	LEGAL FEES	#99-176	3.8	165
				TOTAL LEGAL	**$1,501.32**				
118607000000000	1999-06-30	157326	1789	NEWS JOURNAL	$420.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157603	2152	SENTINEL-ECHO, THE	$473.45	NEWSPAPERS ADS	# 99-176		
118607000000000	1999-06-30	157619	2411	TIMES-TRIBUNE, THE	$279.63	NEWSPAPERS ADS	# 99-176		
118607000000000	1999-06-30	157899	3148	WINCHESTER SUN, THE	$338.17	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157262	3335	FLEMINGSBURG GAZETTE	$157.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157573	3607	NEWSPAPER HOLDINGS INC	$406.88	NEWSPAPERS ADS	# 99-176		
118607000000000	1999-07-31	158275	33	ADVOCATE PUBLISHING CO	$724.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-18	156745	210	BATH COUNTY NEWS OUTLOOK	$425.25	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158293	256	BEREA CITIZEN	$182.25	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158312	485	CENTRAL RECORD	$270.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-02	157926	3302	CITIZEN ADVERTISER	$525.69	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158317	564	CLAY CITY TIMES	$628.56	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-18	157262	3335	FLEMINGSBURG GAZETTE	$157.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-08-25	158838	1242	JACKSON COUNTY SUN	$850.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158378	1261	JESSAMINE JOURNAL	$384.39	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-22	157978	3319	LESLIE COUNTY NEWS	$976.50	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-30	158058	1473	LEXINGTON HERALD LEADER	$1,934.49	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-30	158398	1557	MANCHESTER ENTERPRISE	$775.47	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158266	3688	MAYSVILLE NEWSPAPERS	$1,151.60	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158408	1645	MIDDLESBORO DAILY NEWS	$709.80	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158195	1720	MT STERLING ADVOCATE	$133.92	NEWSPAPERS ADS	#99-176		
118607000000000	1999-06-30	157326	1789	NEWS JOURNAL	$420.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-26	157995	1789	NEWS JOURNAL	$840.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158423	1789	NEWS JOURNAL	$840.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158424	3607	NEWSPAPER HOLDINGS INC	$813.76	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158432	1923	PINEVILLE SUN	$775.47	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158442	2069	RICHMOND REGISTER	$722.52	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158453	2152	SENTINEL-ECHO, THE	$946.90	NEWSPAPERS ADS	#99-176		

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
Rate Case Expenses
for period ended 8/31/99

Item 48a

AC#	Date	Check #	Vendor	Vendor Name	Amount	Description		Hours	Rate/Hr
118607000000000	1999-07-26	158029	2409	THREE FORKS TRADITION	$450.00	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-31	158472	2411	TIMES-TRIBUNE, THE	$559.26	NEWSPAPERS ADS	#99-176		
118607000000000	1999-07-22	157899	3148	WINCHESTER SUN, THE	$676.34	NEWSPAPERS ADS	#99-176		
				TOTAL NEWSPAPER ADS	**$18,950.30**				
118607000000000	1999-06-18	156715	3334	NATIONAL CITY	$134.10	SUPPLIES	#99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$508.48	SUPPLIES	#99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$769.86	SUPPLIES	#99-176		
118607000000000	1999-06-30	157892	3334	NATIONAL CITY	$1,619.61	SUPPLIES	#99-176		
118607000000000	1999-07-31	158268	3334	NATIONAL CITY	$230.87	SUPPLIES	#99-176		
118607000000000	1999-08-19	158712	3230	MARY STEELE	$850.05	SUPPLIES	#99-176		
				TOTAL SUPPLIES - OTHER	**$4,112.97**				
				TOTAL RATE CASE EXPENSE @ 7/22/99	**$70,952.31**				

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

ORDER

IT IS ORDERED that Delta Natural Gas Company ("Delta") shall file the original and 15 copies of the following information with the Commission within 10 days of this Order, with a copy to all parties of record. Each copy of the information requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure its legibility. When the requested information has been previously provided in this proceeding in the requested format, reference may be made to the specific location of that information in responding to this Order. When applicable, the requested information should be provided for total company operations and jurisdictional operations, separately.

1. Refer to Delta's Response to the Attorney General's Initial Request for Information, Item 116. Provide the cost-of-service model on electronic media (e.g., computer diskette, CD-ROM). **This model shall contain formulas rather than values.**

2. a. How will Delta's acquisition of the assets of Mt. Olivet Natural Gas Company[1] ("Mount Olivet") affect Delta's revenues? Revise Application Schedules 24, 25, and 38 (and any other schedule deemed appropriate) to reflect the effects of this acquisition. For each element of rate base, capital structure, operating revenue, and operating expense, state the effect of Delta's acquisition. Provide all workpapers, state all assumptions, and show the calculations used to derive each revised element.

b. Provide a comparison of Delta's proposed rates and charges with the rates and charges that Delta would have proposed had the effect of Delta's acquisition been included in Delta's pro forma operations.

3. In Case No. 95-098,[2] Delta argued that Delta's customers were best served by its transfer of its Canada Mountain storage field assets ("Canada Mountain") to Deltran, Inc. ("Deltran") and its recovery of the storage project costs through Delta's gas cost recovery ("GCR") mechanism. Is it still in the best interest of Delta's customers to permit Delta's recovery of Canada Mountain project costs through Delta's GCR rather than through general rates? If yes, why?

4. Explain why Delta did not propose in this proceeding to include the recovery of Canada Mountain in its base rates.

5. a. Recalculate Delta's revenue requirement to reflect recovery of the Canada Mountain costs through the base rates rather than through Delta's GCR. Revise Application Schedules 24, 25, and 38 (and any other schedule deemed

[1] See Case No. 98-613, The Application of Delta Natural Gas Company, Inc. for an Order Authorizing the Purchase of the Assets of the Mt. Olivet Natural Gas Company (September 7, 1999).

[2] See Case No. 95-098, The Application of Delta Natural Gas Company, Inc. for an Order Authorizing the Purchase and Financing of the Canada Mountain Gas Storage Field (September 7, 1995).

appropriate) to reflect the effects of this change in the method of cost recovery. For each element of rate base, capital structure, operating revenue, and operating expense, state the effect of changing the method of cost recovery. Provide all workpapers, state all assumptions, and show the calculations used to derive each revised element.

c. Provide a comparison of Delta's proposed rates and charges with the rates and charges that Delta would have proposed had recovery of Canada Mountain been through Delta's base rates.

d. Describe the effect on Delta's GCR if the Commission determined that the costs of Canada Mountain facilities should be recovered through base rates.

6. a. When did Delta complete the construction of its Canada Mountain facilities?

b. If the construction is not completed,

(1) What percentage of the project has been constructed as of the date of Delta's Response?

(2) What is the current estimated cost of the Canada Mountain facilities?

(3) What is the expected date of completion?

7. State the percentage of Canada Mountain's storage capacity that Delta is currently using.

8. Provide all contracts and lease agreements between Delta and Deltran that involve the Canada Mountain storage facilities.

9. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 23.

a. Reconcile the $14,323,170 Utility Plant adjustment for Canada Mountain with the $14,423,765 Canada Mountain investment deemed reasonable in Case No. 98-055.[3]

b. Provide all workpapers, state all assumptions, and show all calculations used to derive the following proposed adjustments:

(1) $3,099,324 - "Back out storage gas in Canada Mountain"

(2) $185,781 - "Back out balance of investment in subsidiaries"

(3) $1,049,138 - "Back out non rate base item"

c. Delta states that Adjustment No. 15 is "[t]o adjust for proposed capital structure and difference in rate base and capital structure." Provide a detailed analysis describing the components that make up the difference in Delta's rate base and capital structure.

10. Provide the journal entry that Delta recorded to reflect its purchase of the gas utility facilities of the city of North Middletown, Kentucky ("North Middletown").

11. a. Does Delta propose to recover through its general rates any utility plant acquisition adjustment that resulted from its acquisition of the North Middletown facilities?

b. If yes, provide documentary evidence to demonstrate that:

(1) The purchase price was established upon arms-length negotiation.

[3] Case No. 98-055, Tariff Filing of Deltran, Inc. to Establish its Monthly Lease Charge (April 24, 1998).

(2) The initial investment plus the cost of restoring the facilities to required standards will not adversely impact the overall costs and rates of the existing and new customers.

(3) Operational economies can be achieved through the acquisition.

(4) The purchase prices of utility and non-utility property are clearly identified.

(5) The purchase price results in overall benefits in the financial and service aspects of Delta's operations.

12. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 25(a). Explain why the following rate base items should not be allocated for rate-making purposes to Delta's subsidiaries:

a. Prepayments.

b. Materials and Supplies.

c. Gas In Storage.

d. Unamortized Debt

e. Advances for Construction.

13. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 26(b). Delta's original revenue requirement of $7,085,868 reflects an overall return on capital of 9.235 percent.[4] In its response Delta shows that its proposed adjustment to rate base will result in an increase to its revenue requirement of $33,896. State whether the proposed $33,896 increase to Delta's revenue requirement will result in a return on capital greater than Delta's requested return.

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[4] $7,085,868 Requested Return / $76,728,462 Proposed Capital = 9.235%.

14. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 27.

a. Reconcile the $1,551,279[5] of net TranEx plant addition with the $1,587,945 TranEx adjustment included in Delta's Response to Item 23 of the Commission's Order of August 11, 1999.

b. Reconcile the $4,044,291 of TranEx plant with the journal entry of $4,300,000 for Plant In Service that the Commission directed in its Order of June 27, 1999 in Case No. 97-140.[6]

15. Provide TranEx's 1998 balance sheet, income statement, statement of retained earnings, and cash flow statement.

16. Provide Enpro's 1998 balance sheet, income statement, statement of retained earnings, and cash flow statement.

17. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 27.

a. Does the $1,587,945 TranEx adjustment include a utility plant acquisition adjustment?

b. If yes, provide documentary evidence to demonstrate that:

(1) The purchase price was established upon arms-length negotiation.

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[5] $4,046,127 TranEx Plant - $2,494,848 TranEx Depreciation = $1,551,279.

[6] Case No. 97-140, The Application of Delta Natural Gas Company, Inc. for an Order Authorizing the Purchase of All of the Issued and Outstanding Stock of the TranEx Corporation (June 27, 1997) at 6.

(2) The initial investment plus the cost of restoring the facilities to required standards will not adversely impact the overall costs and rates of the existing and new customers.

(3) Operational economies can be achieved through the acquisition.

(4) The purchase prices of utility and non-utility property are clearly identified.

(5) The purchase price results in overall benefits in the financial and service aspects of Delta's operations.

c. Upon what cost methodology (original cost or current market value) was the purchase price of TranEx based?

18. Provide all contracts and lease agreements between Delta and TranEx.

19. Explain why Delta proposed to recover its TranEx acquisition costs through its base rates, but proposed a different method of recovery for its Deltran acquisition costs.

20. a. Describe the procedures that Delta uses to identify, assign, and allocate costs to Canada Mountain and TranEx.

b. Provide all internal memoranda, correspondence, policy manuals and other documents that discuss these procedures.

21. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 29(b).

a. Explain why Delta annualized the pay period ending December 31, 1998 rather than apply the wages effective July 1, 1998 to the actual hours worked in 1998 to arrive at its pro forma salaries and wages.

b. Provide all workpapers, state all assumptions, and show all calculations used to derive the $5,873,600 of wages effective February 18, 1998.

c. Provide all workpapers, state all assumptions, and show all calculations used to derive the $6,042,900 of wages effective July 1, 1998.

22. Refer to Delta's Response to the AG's Initial Information Request, Item 36.

a. Provide a detailed analysis of Delta's 1998 salaries and wages that were allocated to clearing accounts. This analysis shall include descriptions and titles of each clearing account included in the allocation.

b. Explain why Delta did not adjust its pro forma salaries and wages to reflect the test period allocations to the clearing accounts.

23. a. Calculate Delta's pro forma salaries and wages using (1) the actual regular hours for 1998; (2) the actual overtime hours for 1998; and (3) the July 1, 1998 wage rates. The calculation shall be provided in the format attached hereto as Schedule 23a.

b. State the amount of pro forma salaries and wages set forth in Delta's Response to Item 23(a) that should be capitalized. Provide all workpapers, state all assumptions, and show all calculations used to derive the capitalized pro forma wages.

c. State the amount of pro forma salaries and wages set forth in Delta's Response to Item 23(a) that should be allocated to the clearing accounts. Provide all workpapers, state all assumptions, and show all calculations used to derive the allocated pro forma wages.

24. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 30(b). For each account included in the breakdown of the Canada Mountain

expenses, provide the account title and descriptions of the costs included in the account.

25. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 30(c). For each account included in the breakdown, provide a detailed analysis of the expense items that have been removed and those expense items remaining. The detailed analysis shall include the title and brief descriptions of each expense item.

26. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 30e. Explain why a 3-year amortization period should be used rather than the 5-year amortization period that the Commission applied to these expenses in Case No. 97-066.[7]

27. Item 19 of the AG's Initial Information Request includes a list of the unamortized deferred income tax balances Delta was allowed to recover in Case No. 97-066. Explain why Delta should recover any of the following unamortized deferred income taxes for which recovery was not permitted in Case No. 97-066:

a.	A/C 1282020	Def Inc Tax Pension Plan	$(567,200)
b.	A/C 1282030	Def Inc Tax Stock Plan	$ 22,600
c.	A/C 1282060	Def Inc Tax Annual Leave	$ 153,500
d.	A/C 1282080	Def Inc Tax Amort Ferrin Prom Note	$ 16,200
e.	A/C 1282110	Def Inc Tax Net Unbilled Rev	$ 670,100
f.	A/C 1282110	Def Inc Tax Bad Debt Res	$ 47,300

[7] Case No. 97-066, An Adjustment of the General Rates of Delta Natural Gas Company (December 8, 1997).

g.	A/C 1282110	Def Tax Regulatory Inc Tax	$	(500)
h.	A/C 1283020	Def Tax Regulatory ITC	$ 392,500	

28. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 35. Explain why Delta did not use the federal statutory income tax rate of 35 percent to calculate its unamortized deferred income tax items.

29. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 36. Is the difference between Delta's rate base and capitalization due to capital supporting items that are not allowed for rate-making purposes?

30. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 57(b). Describe the cause(s) of the increase of $4,685,000 in Delta's short-term debt, of the increase of $634,000 in Delta's long-term debt, and of the decrease of $321,000 in Delta's common equity.

31. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 57(c).

a. Provide a detailed narrative discussing the "financial stress" that Delta is experiencing.

b. What assurances does the Commission have that Delta will use its earned returns to increase its equity component?

32. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 60. Explain why Delta has not reflected its hypothetical capital structure in its 1999 or 2000 budgets.

33. State Delta's current short-term debt cost rate.

34. Refer to Direct Testimony of John F. Hall at 5. Provide the calculations that produce a 9.31 percent cost of capital. Reference to Delta's Response to AG's Initial Information Request, Item 2(c) and 2(d), will not be considered responsive.

35. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 53. The analysts' reports stress the negative impact of warm weather on Delta's earnings. What effect, if any, would Delta's implementation of its proposed Weather Normalization Adjustment Clause have on these analysts' views?

36. Refer to Direct Testimony of Martin J. Blake, Exhibit MJB-4. What discounted cash flow estimated return on equity for Delta, if any, did Ibbotson Associates report in its Cost of Capital Quarterly (March 1999)?

37. At page 27 of his Direct Testimony, Dr. Blake using the capital asset pricing model ("CAPM") calculated an estimated return on equity of 11.88 percent based upon the lowest beta coefficient reported (0.40), and an estimated return on equity of 15.08 percent based percent based upon the highest beta coefficient of 0.80. Assuming the lowest reported beta coefficient was .02, would 11.88 percent be the more appropriate return on equity to use when analyzing Delta's required return on equity?

Done at Frankfort, Kentucky, this 14th day of September, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

Delta Natural Gas Company, Inc.

CASE NO. 99-176

Pro Forma Salaries and Wages

	Wages		Hours Worked		Pro Forma Salaries and Wages		
Employee Name/Number	Effective 2/18/98	Effective 7/1/98	Regular	Overtime	Regular	Overtime	Total

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

Adjustment of Rates of	)	
Delta Natural Gas Company, Inc.	)	Case No. 99-176

RECEIVED
SEP 03 1999
PUBLIC SERVICE COMMISSION

SUPPLEMENTAL REQUEST FOR INFORMATION BY THE ATTORNEY GENERAL

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office for Rate Intervention, and submits these Requests for Information to Delta Natural Gas Company, Inc., to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the company witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify

each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(9) In the event any document called for has been destroyed or transferred beyond the control of the company state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

Respectfully Submitted,

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

CERTIFICATE OF SERVICE AND OF FILING

I hereby certify that this the 3rd day of Septembert, 1999, I have filed the original and ten true copies of the foregoing with Hon. Helen C. Helton, Executive Director of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky, 40601 and that I have served the parties by mailing the same, postage prepaid, to:

ROBERT M WATT III ESQ
STOLL KEENON & PARK LLP
201 EAST MAIN STREET
LEXINGTON KY 40507-1380

JOHN F HALL
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

[signature]

DELTA NATURAL GAS COMPANY
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

1. With regard to the response to AG-5, please provide the following information:

   a. The data response shows a net investment amount by Delta in Enpro of $216,236 and a receivable from Enpro of $1,231,901. Please provide information showing how the "net plant amount for Enpro" of $1,280,279 can be derived from the numbers listed above.

   b. Provide detailed financial statements for Enpro for the year 1998 showing, at a minimum, the Enpro balance sheet information from which the net plant amount for Enpro can be derived

   c. Why has Delta chosen the current approach of considering only the "net plant amount for Enpro" as the subsidiary equity investment to be removed from rate base? Also explain why Delta has not used the amount of $1,466,060 as its subsidiary equity investment to be removed from rate base?

   d. Explain to what extent the Company's approach and components in the current case to determine its subsidiary equity investment are different from the approach and components in the prior case to determine its subsidiary equity investment.

2. With regard to the responses to AG-5 and AG-7, please provide the following information:

   a. AG-5 shows that Delta's equity investment in Tranex is $885,475 plus $504,706, or $1,390,181. AG-7 shows that the Tranex net plant proposed to be added to rate base by Delta is $1,587,945. Please provide detailed financial statements for Tranex for the year 1998 showing, at a minimum, the Tranex balance sheet information from which the net plant amount for Tranex and Delta's equity investment of $1,390,181 can be derived.

   b. In which accounts are the Tranex plant balance of $4,044,291, the Tranex CWIP balance of $38,502 and the Tranex accumulated depreciation of $2,494,848 recorded on the books of Delta? Provide plant account numbers and account descriptions.

3. With regard to the net Tranex plant investment of $1,587,945, provide the following information:

   a. Detailed description of the functions of this plant and whether this plant is used and useful in servicing Delta's ratepayers.

   b. Reasons why this non-regulated subsidiary plant should be included in regulated rate base to be financed by the ratepayers.

c. How do Delta and Tranex account for the revenues for the products and services of Tranex? If there are revenues generated by Tranex, for what products and services were they and how much were these revenues in 1998.

4. Is Delta in this case giving recognition to the revenues generated by Tranex in 1998? If so, how much were these revenues and in which filing schedule or workpaper are these revenues reflected? If not, why not?

5. Are there any expenses and taxes associated with the Tranex plant included in the above-the -line test year operating results? If not, why not? If so, identify the types and amounts of these expenses and taxes and show in which filing schedule or workpaper these expenses and taxes are reflected.

6. The response to AG-8 shows CWIP data for 1997 that are exactly the same as those for 1998. This must be an error. Please provide a revised schedule showing the correct monthly and monthly average CWIP balances (w/o Canada Mountain) for 1997.

7. In response to PSC data request 12 in Delta's prior rate case, the Company provided totally different monthly CWIP balances for 1996 than are shown for the same months in the response to AG-9 in the current case. Please provide a reconciliation of these balances.

8. With regard to the response to AG-11 b, please provide the following information:

   a. Reconcile the total Tranex plant amount of $5,014,488 to the Tranex plant amount of $4,044,291 included in Delta's rate base plant in service, as per the response to PSC data request 28.

   b. Why does the Company believe it appropriate to reflect depreciation expenses on Tranex investment that is still classified as CWIP on 12/31/98? Also, reconcile this with the fact, that the Company has not reflected depreciation expenses on Delta expenditures that were still classified as CWIP on 12/31/98 (i.e., the Company is not calculating and reflecting depreciation on its 12/31/98 CWIP balance (net of CM) of $1,169,046)

9. With regard to the so-called "1/8th method" used by the Company to approximate its cash working capital requirement, please provide the following information:

   a. This cash working capital "shortcut" method essentially assumes that there is a 45-day difference between the time it collects its revenues and the time it pays its operation and maintenance expenses. Please confirm your agreement. If you do not agree, explain your disagreement.

b. The cash working capital requirement is determined by applying a factor of 1/8 (the assumed 45-day net revenue collection lag = 45 / 365 = 1/8) to the Company's operation and maintenance expenses. Please confirm your agreement. If you do not agree, explain your disagreement.

c. The Company's payment lags associated with its operation and maintenance expenses do not include any payment lags associated with capitalized items included in rate base such as plant in service and CWIP. Please confirm your agreement. If you do not agree, explain your disagreement.

10. With regard to the response to AG-17, please provide the following information:

a. What represents the difference between, for example, the 12/31/98 balance of $3,391,350 on the Company's Trial Balance and in response to AG-17 and the 12/31/98 balance of $220,060 claimed as a rate base deduction.

b. Provide the response to AG-17, but showing the balances that are equivalent to the 12/31/98 balance of $220,060

11. With regard to the response to AG-22, please provide the following information:

a. Provide the journal entries (showing account numbers and descriptions and associated dollar amounts) for the establishments of the $126,000 Medical Self Insurance reserve on 6/30/94 and the $25,000 for Other Self Insured reserve on 6/30/92.

b. What were the balances for these two reserve accounts from their respective inceptions until today?

12. Please provide the rate effective dates of Delta's most recent 5 base rate proceedings (also show case numbers).

13. With regard to the response to PSC data request 32 b, please provide the following information:

a. Does the Company only pay property taxes on plant or also on CWIP and cushion gas?

b. If the Company only pays property taxes on plant, does this involve the total plant in service balance or only selected plant items?

c. For 12/31/98, the total plant in service balance is $119,758,525, of which $10,391,000, or 9.5% represents the Canada Mountain portion. What would be the 12/31/98 numbers if one were to consider only the selected plant components upon which property taxes are assessed? In addition, provide these selected plant components by account number and description and associated dollar amount.

d. Confirm that the actual test year property taxes that are included in the taxes other than income taxes amount on line 8 of Schedule 6 amount to $742,584, not $722,000.

e. The Company has calculated the pro forma test year property taxes by taking the actual 1998 property taxes of $742,584 as the starting point and then subtracting from this amount Canada Mountain related property taxes of $47,147 that were calculated by applying a Canada Mountain allocation ratio to a property tax level of $722,000. Please confirm that there is a logic error in this proposal. The Company should have applied the appropriate Canada Mountain property tax allocation ratio to the actual 1998 property tax amount that is included in the test year. If you do not agree, explain your disagreement in detail.

14. With regard to the response to AG-44, please provide the following information:

a. Are there no Christmas bonus expenses reflected in the 1998 test year operating expenses? If so, what is the expense amount and in which account are they reflected?

b. Are the $24,000 for Mr. Jenning's loan forgiveness compensation included in the pro forma adjusted test year operating expenses? If so, in which account are they reflected and where are they reflected on the Company's filing schedules or workpapers?

15. With regard to the items listed for "Company Relations Expenses" (totaling $32,496) in the response to PSC data request 25 b, please explain the purpose and function of the following items:
- Delta story history booklets.
- Sample Tie Tac
- All items under Vendor # 3334 and 3364 for denim shirts, totaling $9,474
- Door prizes employee meeting
- Extra large awards jackets
- Custom caps with embroidery
- Award knives #7200
- Employee service awards per AT
- Land's End advertising for denim shirts - Delta Logo

16. With regard to the response to AG-47, please provide the following information:

a. The Canada Mountain amount of $13,580,916 is the depreciated net Canada Mountain plant as of 12/31/98. Please confirm. If you do not agree, explain.

b. The depreciated net total plant for Delta as of 12/31/98 comparable to the depreciated net Canada Mountain plant number as of 12/31/98 amounts to $91,727,652 (see FR 7(a)).

Please confirm. If you do not agree, explain.

c. Provide a workpaper showing the derivation of the Total Plant balance of $128,546,542.

17. With regard to the response to AG-49, please provide the following information:

a. Does this information indicate that during 1998 the Company paid $60,110 in KPSC assessments? If not, provide the correct assessment amount paid in 1998.

b. What represent the DOT Pipeline Safety Program and how long has this program been in effect? Will this program continue at the same level in 1999 and 2000? If so, explain why. If not, explain why not.

c. What were the comparable DOT Pipeline Safety Program expenses in 1995, 1996 and 1997 and for the first 8 months of 1999? What are the budgeted expenses for the full year 1999 and for the year 2000?

18. With regard to the abnormal sales tax booking in 1998 described in response to AG-26, please provide the following information:

a. Describe the nature of the abnormal expense booking of $27,631 and in which account(s) this abnormal booking was recorded.

b. What represents the "sales tax due from audit" expense of $16,915 shown on page 5 of AG-56? Is this an expense booking relating to prior periods as a result of the audit? To what extent does this item relate (and is included in) the amount of $27,631 described in part a?

c. Explain the sales tax audit related items of $(46,490.97) and $26,352.22 on lines 398 and 399 of page 16 of AG-56 and explain to what extent they relate to the amount of $27,631 described in part a.

19. Please identify all items listed in account 1.921.06 in the response to AG-56 that are directly or indirectly related to Canada Mountain.

In addition, provide a description of the nature and purpose of the account 1.191.06 expenses for Tickets for Kings Island, Dollywood, and KY Kingdom.

20. With regard to the travel expenses in account 1.921 shown in the response to AG-57b, please provide the following information:

a. identify all travel expense items that are directly or indirectly related to Canada Mountain.

b. What represents the travel expenses for the Pine Mountain State Resort Park?

21. Please identify all items listed in account 1.921.29 in the response to AG-58 that are directly or indirectly related to Canada Mountain.

22. With regard to the response to AG-53, please indicate what the $180,370 1998 expense for 401(k) would have been with the elimination of the "reclassification of the Pension expense due to an account distribution correction made for a trustee for 1997".

23. The 1998 Trial Balance shows that Delta's 1998 test year expenses include $729,269 for pension expenses. In this regard, please provide the following information:

    a. In the response to PSC data request 44, the Company provided its most recent actuarial report for pensions dated April 1, 1999. Please provide the pension expenses (equivalent to the 1998 reported pension expenses of $729,269) based on the data contained in this latest actuarial report and indicate how this pension expense amount was derived from the data in the report.

    b. Please explain the status of the Company's pension plan (in terms of either being overfunded or underfunded) for each of the last 5 years 1994 through 1998 and, in addition, explain why the pension balance is currently prepaid.

24. It appears from the response to AG-54 that the Company has misinterpreted the question. The data in the current case state that in 1998 the Company received and booked as a credit to its 1998 medical expenses certain stop-loss insurance coverage reimbursements that were applicable to 1997. The question in AG-54b is: for each of the last 10 years, provide any similar reimbursements that were booked as expense credits in any particular year but related to activities in time periods prior to that particular year. Please re-submit your response to this clarified request.

25. Page 16 of 16 of AG-56 shows that the 1998 test year account 1.191.06 of $174,463 includes $87,600 for amortization expenses. In this regard, please provide the following information:

    a. The response to data request PSC-47 indicates that these amortization expenses relate to the amortization of a previous rate case and a management audit expense. Please provide a breakout of the various amortization expenses making up the $87,600.

    b. Describe the nature and case number of the "previous rate case" as well as the time period in which these rate case expenses were incurred.

    c. Describe the nature of the management audit, when this audit was performed. In addition, explain whether this audit was ordered by the KPSC or whether it was implemented at the sole initiative of Delta's management.

d. For each of the expense types that are included in the amortization expense amount of $87,600, provide:

   i. The total cost amount that was originally incurred
   ii. The amortization period and the basis for haven chosen this amortization period.
   iii. Whether the amortization of these expenses over these particular amortization periods were authorized by the KPSC and, if so, provide actual source documentation (e.g., relevant pages from KPSC Orders) to support this claim.

e. Explain why these amortization expenses were not revealed and identified by the Company in its response to AG-23.

26. With regard to account 1.923.04 Outside Services Other, please provide the Columbia Small Customer Group expenses billed to Delta for each of the last 10 years and for the first 8 months in 1999.

27. With regard to the responses to AG-39 and AG-65, please provide the following information:

a. The Company's gas costs for 1998 amounted to $16,260,037 and this amount included $2,112,862 for Canada Mountain gas costs. Please confirm this. If you do not agree, explain your disagreement.

b. Through expense credit account 922.01, the Company removed the $2,112,862 Canada Mountain gas costs from its 1998 O&M expenses (see response to AG-39). Therefore, the net gas costs, exclusive of Canada Mountain, booked in 1998 operating expense amounts to $14,147,177. Please confirm this. If you do not agree, explain your disagreement.

c. Provide the journal entries showing the counter-account for the account 922.01 Canada Mountain expense transfer entry of $2,112,862.

d. If the 1998 GCR revenues of $16,260,037 include Canada Mountain gas cost recoveries, why didn't the Company in 1998 make a GRC booking to remove the Canada Mountain related GCR revenues of $2,112,862, similar to what it booked for its gas costs as described in part b above? If the Company indeed made this booking in 1998, why has it removed the full gas cost recovery amount of $16,260,037 (which still includes the Canada Mountain GCR revenues) from total revenues for ratemaking purposes in this case?

28. The response to AG-66 indicates that the actual collection revenues for the first 7 months of 1999 averaged $10,105 per month as opposed to the average collection revenues of $6,500 per

month in the 1998 test year. Please provide the reasons for the significant increase in these average monthly collection revenues. In addition, provide the actual collection revenues for the month of August 1999.

29. With regard to the response to AG-71, please provide the following information:

    a. Reconcile the actual billed special contract revenues for 1998 on Walker Exhibit 6, page 1 of $511,666 to the actual 1998 special contract revenues of $595,308 in the response to AG-71.

    b. What represents the Fiscal Year 1999 MCF number of 2,226,763, is it the 12-month period ended 6/30/99 or the 12-month period ended 7/31/99 as was requested? In addition, provide the revenues and current average rate/MCF associated with this usage level of 2,226,763.

    c. Do the results to be provided in response to part b include any impact of the "rate switching" listed in the third column of Walker Exhibit 6, page 1? If so, to what extent?

    d. Provide a detailed explanation and workpapers showing the calculations underlying the "rate switching" adjustment of $104,167 on Walker Exhibit 6, page 1.

    e. With regard to the pro forma adjusted special contract revenues of $632,522 in the seventh column of Walker Exhibit 6, page 1, provide the assumed underlying MCF volume, number of customers and average rate per MCF, in the same format as per the response to AG-71.

    f. For each month of 1998 and the first 7 months of 1999, provide the monthly number of special contract customers.

    g. Revised Walker Exhibit 5 in the response to AG-73 shows average monthly customers during 1998 of 7 and 12/31/98 number of customers of 12. Reconcile this to the average monthly customers of 4 shown on the response to AG-71.

30. With regard to the response to AG-70, please provide the following information:

    a. The response shows that in each of the 5 years from 1994 through 1998 the MCF sales volumes and number of customers have grown. Given this data, why hasn't the Company reflected a year-end customer revenue adjustment?

    b. Provide the total MCF volume, number of customers and rate per customer underlying the 1998 test year amount of $1,931,707 shown on Walker Exhibit 6, page 1. In addition, reconcile this information to the number of customers and MCF volumes shown for 1998 in the response to AG-70.

c. For each month of 1998 and the first 7 months of 1999 provide the monthly number of customers for Interruptible Rate 20.

d. Provide the actual customer data for Fiscal Yr. 1999 on the response to AG-70.

e. For each of the years and for Fiscal Yr. 1999 on the response to AG-70, provide the actual revenues booked. If the 1998 revenues do not amount to $1,931,707, please provide a reconciliation.

f. Provide a year-end customer revenue adjustment for this rate class based on the difference in the average 1998 monthly customers and the 12/31/98 level of customers. Provide workpapers.

31. With regard to Firm Rates 10 &15 and the response to AG-69, please provide the following information:

a. Provide the total MCF volume, number of customers and rate per customer underlying the 1998 test year amount of $1,469,977 shown on Walker Exhibit 6, page 1. In addition, reconcile this information to the number of customers and MCF volumes shown for 1998 in the response to AG-69

b. For each month of 1998 and the first 7 months of 1999 provide the monthly number of customers for Firm Rates 10 &15.

c. For each of the years and for Fiscal Yr. 1999 on the response to AG-69, provide the actual revenues booked. If the 1998 revenues do not amount to $1,469,977, please provide a reconciliation.

d. Provide a year-end customer revenue adjustment for these rate classes based on the difference in the average 1998 monthly customers and the 12/31/98 level of customers. Provide workpapers.

32. With regard to the response to AG-76, provide the following additional information:

a. The non-labor related operation expenses for Underground Storage (FERC Form 2, page 320, line 114)

b. The non-labor related operation expenses for Transmission (FERC Form 2, page 323, line 191)

c. The non-labor related operation expenses for Distribution (FERC Form 2, page 324, line 216)

33. Reference AG data request no. 83. For the cycles selected, please provide the information requested in (a) through (e) for each month of the 1998-99 winter, including November, December, January and February, in addition to the two months already provided.

34. Reference AG data request no. 94. The response states that the Company reviews the expected construction footage and potential in any area for new service. Please provide whatever information is prepared for managers to review who are responsible for the approval of such projects, as requested in AG-94. Also keep in mind, that a construction project may involve a mains extension to provide service to new commercial or industrial customer rather than generally into a new area. What is sought here is real information provided to managers which would undoubtedly include a brief project description, perhaps a listing of the pipe and other capital improvements related to the project, and the estimated cost, perhaps a history of the reason or justification for the project and perhaps the timing. For many LDCs, this information is often contained on one or two sheets presented to management for approval.

35. Reference AG data request no. 96.

    a. If there is a specific portion of the referenced text that discusses the weighting scheme, please provide it.

    b. In addition to the requested material in a. above, please provide a copy of any authoritative source of which Mr. Seelye is aware that discusses or shows the application of the weighting scheme to the zero intercept methodology specifically, or shows an application of the weighting scheme for any public utility purpose.

    c. Please provide references and copies of pertinent portions of any regulatory commission orders that Mr. Seelye is aware that approves or authorizes the weighting scheme proposed by Mr. Seelye in this case.

36. Again, referencing AG data request no. 96. Please explain the theory of what is being accomplished by Mr. Seelye's proposed price-weighting scheme, and how weighted prices are more reasonable for use in regression analysis than unweighted prices.

37. Reference AG data request no. 98.

    a. The map provided does not specify, as requested, pipeline interconnections, any LNG or other peak shaving facilities. Please provide another map showing this requested information.

    b. Provide a key to the map provided in response to AG-98.

    c. Indicate on-system storage.

d. Indicate Delta's compressor stations used for delivery system pressure purposes (not for storage injection), if any.

38. Reference AG data request 99. Part (b) requested an explanation of how each demand allocation differs from the other demand allocators. As follow-up:

a. Please explain the theory behind DEM04 not including 3,973 Mcf of demand for Special Contract customers that is included in Special Contract customers DEM03. Explain what there is about this difference that makes sense from an allocation perspective, given the costs to which DEM03 and DEM04 are applied.

b. Explain the theory and why it makes sense to include 3,874 Mcf of demand in Off-systems Transportation customer DEM03, but no demands for these customers in DEM04.

c. Responses b. and c. to AG-99 refer the reader to page 9 of Mr. Seelye's testimony. Therein is a reference for the reader to see Walker Exhibit 4. Walker Exhibit 4 appears to contain actual and normal weather-related data. Please provide the calculation that use the "base loads and temperature-sensitive loads" [Seelye, Testimony, pages 8-9] to arrive at the DEM03 demands.

39. Reference AG data request no.100. For DEM01 and DEM03-05, please provide the absolute amount of interruptible load included in each factor.

40. Reference AG data request no. 102. Please provide any interruptible load included in the estimated peak day requirements shown for each year.

41. During each peak day identified in response to AG-102, please provide for each transportation customer whose gas usage can be determined on a daily basis the amount of gas usage, and the amount of nominations for that customer. If one third-party supplier is responsible for supplying more than one of Delta's customers, the metered usage and nominations can be aggregated so it will be obvious to the reader how much gas was nominated for such customers and used by such customers.

42. Reference AG data request no. 102.

a. For each of the three estimated peak day requirements provided, please separately state the requirements for interruptible and for firm transportation customers.

b. For each of the three actual peak day sendouts provided, please separately provide the actual gas usage by interruptible and by firm transportation customers.

43. Please indicate whether the following costs related to company-owned storage service are recovered in base rates or in gas cost rates.

   a. Fixed costs (i.e., return, return-related taxes, depreciation).

   b. Variable costs (O&M-related storage service).

   c. Other. Explain.

44. Please provide the total company-owned storage-related costs included in test year costs of service, broken down by fixed costs (and the component parts of fixed costs) and by variable costs (and the component parts of variable costs). The term component parts simply refers to the finest breakdown that already exists at the Company.

45. Please separately provide the amount of test-year contract storage costs that are included in costs at issue in this proceeding. Itemize by fixed and variable as those terms are used in AG 2-11 above. If any or all contract storage costs are recovered in the Company's gas cost recovery mechanism, please so indicate and provide the amounts for, preferably, the test year, or for the most recent 12-month period available.

46. Please list and explain each and every benefit that Delta gets from its storage services that justifies the costs of the storage services.

47. a. How many customers are served from pipe which is classified as transmission pipe?

   b. Please state minimum observed line pressures over the past three years on transmission pipe segments from which customers are directly served.

   c. Please state the acceptable, or normal, operating pressure ranges on the various transmission pipe segments from which customers are directly served.

48. Special Contracts and Off-System Transportation customer DEM03 amounts appear to be based on a 100 percent load factor (i.e., annual commodity ÷ 365).

   a. Confirm, or explain this coincidence.

   b. Of the answer to a. is "confirmed," why is this 100 percent load factor method used to determine these customer DEM03 amounts?

   c. Please provide the SP1 and OS test year class non-coincident peak demands, or if not known, the individual SP1 and 05 customer peak demands.

   d. Please provide the SP1 and OS test year demands coincident with system peak.

49. Please explain how the Delta system is used that makes it reasonable for OS customers to be responsible for an allocated share of transmission costs (by virtue a positive DEM03), but not to receive an allocated share of distribution costs (by virtue of zero DEM04 and DEM05).

50. Reference the response to AG 103. Please confirm or correct that the Company maintains the following capacity resources to meet its design peak day requirements:

Firm Transportation

Tennessee	FT-A	1,400 Dth
	FT-G	16,211 Dth
Columbia/Gulf	GTS	12,070 Dth
	GTS	310 Dth
	Subtotal	29,991 Dth

Storage

Contract		
Tennessee	FS-MA	8,363 Dth
	FS-PA	1,524 Dth
Columbia	GTS	10,216 Dth
	Subtotal	20,376
On-System		
Canada Mountain		28,000 Mcf
Kettle Island		2,000 Mcf
	Subtotal	30,000 Mcf
Total Capacity Resources		80,367 Dth

51. Identify and explain any differences in the Company's current capacity resources and those identified above.

52. Reference the response to AG 103. Please identify the current rates and monthly costs applicable under each arrangement. Show all billing determinants and rates.

53. With respect to charges for balancing service provided to transportation customers:

   a. Please identify each charge applicable to transportation customers.

   b. Provide an explanation and calculation showing how those charges were designed.

c. Explain why such charges are adequate and reasonable.

d. Identify the extent to which purchased gas costs and on-system storage related costs are received from transportation customers for balancing or other purposes (explain).

54. Reference the Company's cost of service study. Please provide a detailed explanation of the following line items:

a. Exhibit 1-5. Please explain the nature of the following adjustments and explain why the proposed cost of service study treatment is reasonable.

1. Tranex Plant 367-371
2. Tranex Acquisition Adjustment
3. Circle R
4. Canada Mountain

b. Exhibit 1-9. Please explain the nature of the following adjustments and explain why the proposed cost of service study treatment is reasonable.

1. Tranex Plant PT365
2. Tranex Plant PT389
3. Canada Mountain

c. Exhibit 1-13. Please explain the nature of the Remove Canada Mountain adjustment and explain why the proposed cost of service study treatment is reasonable.

55. Reference the Company's cost of service study, Exhibit 2-29. Please identify the source of the allocation vector OMTT.

56. Please provide a schedule showing actual monthly deliveries on behalf of transportation customers and actual usage for the period November 1995 to present.

57. Reference the response to AG 102. Please identify actual deliveries to Delta on behalf or third-party transportation on peak day for the 1996-97, 1997-98 and 1998-99 winter seasons.

58. Please provide complete output from the statistical software package utilized by Mr. Seelye for his regression that produced the $3.1410884 zero intercept. (Exhibit 4-3)

59. Did Mr. Seelye perform an unweighted regression while investigating the zero intercept methodology? Or since? If yes, please provide the complete output from the statistical software package used for this determination.

Randall J. Walker
Senior Consultant
The Prime Group, LLC.
6711 Fallen Leaf
Louisville, Kentucky
40241

RECEIVED

SEP 2 1999

GENERAL COUNSEL

September 1, 1999

James R. Goff
Public Service Commission
730 Schenkel Lane
Post Office Box 615
Frankfort, Kentucky 40602

RECEIVED
SEP 02 1999
PUBLIC SERVICE COMMISSION

Re: Case No. 99-176, Delta Natural Gas Company, Inc.

Dear Mr. Goff:

Enclosed is a diskette containing the electronic file requested by the Commission in Question No. 6 of its Order dated August 11, 1999.

The diskette was inadvertently omitted from the responses filed by the Company to Commission's data request. We regret any inconvenience caused by this oversight.

Respectfully Submitted,

Randall J. Walker

Randall J. Walker
Senior Consultant
The Prime Group
(502) 957-2829

Enclosure

Copy and Enclosure To:
Elizabeth E. Blackford
Assistant Attorney General

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

September 2, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

<u>O R D E R</u>

IT IS ORDERED that Delta Natural Gas Company, Inc. ("Delta") shall file the original and 12 copies of the following supplemental request for information with the Commission, with a copy to all parties of record, no later than September 13, 1999. Each copy of the information requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure its legibility. When the requested information has been previously provided in this proceeding or in Case No. 99-046[1] in the requested format, reference may be made to the specific location of that information in responding to this Order. When applicable, the requested information should be provided for total company operations and jurisdictional operations, separately.

[1] Case No. 99-046, Delta Natural Gas Company, Inc. Experimental Alternative Regulation Plan.

1. Refer to Delta's response to Item 56 of the Commission's August 11, 1999 Order.

a. Discuss the appropriateness of using an imputed capital structure as an integral part of a rate mechanism that is established to provide incentives based on actual performance.

b. Using the most recently ended fiscal year and Delta's existing rate structure, employ the alternative rate mechanism proposed by Delta, including use of an imputed capital structure, as though the mechanism, as proposed, was approved and in place at the beginning of the budgetary cycle. Include all financial statements, workpapers, calculations, assumptions, and other documentation necessary to support the results.

2. Calculate the rate of return on common equity that Delta would have generated assuming normal weather patterns and, hence, normal gas consumption patterns for each of the last 5 years. For calculation purposes, adjust any and all expenses for which a direct relationship to weather and consumption can be made.

3. Refer to Delta's response to Item 59 of the Commission's August 11, 1999 Order.

a. For each account listed, provide the annual budget-to-actual variance in both total dollars and as a percentage of both the budget and the actual.

b. Provide the information requested in (a) above for fiscal years 1997, 1996, 1995 and 1994. Include with this response the budget and actual results for the years not already provided.

c. Provide a detailed explanation for any variances in excess of 10 percent. Exclude variances that are the lesser of $5,000 or 5 percent.

4. Refer to pages 8 and 9 of the July 30, 1999 Direct Testimony of Thomas S. Catlin filed in Case No. 99-046 and incorporated herein. Beginning on line 24, page 8, and continuing on through line 8, page 9, Mr. Catlin states that "the incentive to control costs which is created by the 5 percent limit on the increase in the AAC is largely, if not totally superseded by the Company's ability to recoup any shortfalls through the AAF." Does Delta agree with this conclusion? If not, explain why not?

5. Refer to page 10 of the July 30, 1999 Direct Testimony of Thomas S. Catlin filed in Case No. 99-046 and incorporated herein. Mr. Catlin states, beginning at line 19, "Hence, the Company's proposal to limit the increase in O&M expenses per customer which can be passed through to customers to the rate of inflation (plus an additional 1.5 percent) is not an effective limit and does not create a true incentive to control costs." Does Delta agree with this conclusion? If not, explain why not?

6. Refer to page 12 of the July 30, 1999 Direct Testimony of Thomas S. Catlin filed in Case No. 99-046 and incorporated herein. Beginning on line 3, Mr. Catlin states, "A performance-based control should be designed to reward performance which is better than has historically been achieved without the performance mechanism in place (or penalize performance which is worse than historically achieved). Delta's plan does not work in this manner." Does Delta agree with this statement? If not, why not?

7. Refer to Delta's response to Item 3 of the Commission's August 11, 1999 Order.

a. Delta has suggested three rate schedules: residential, small non-residential firm service, and large non-residential firm service. For each of these, submit Delta's recommendation for the customer charge and base rate.

b. How would Delta propose to classify its customers for service in the two non-residential categories? In other words, what is the distinction between small and large non-residential service?

Done at Frankfort, Kentucky, this 2nd day of September, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602
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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen C. Helton
Executive Director
Public Service Commission

September 1, 1999

Mr. Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, Kentucky 40507

Ms. Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Re: Case No. 99-176
Delta Natural Gas Company

Dear Ms. Blackford and Mr. Watt:

In Delta's Response filed with the Commission on August 23, 1999, it was discovered that a disk referenced in the response to question 6 of the Commission's Order of August 11, 1999, was missing. It appears to have been inadvertently omitted. Delta must mail the disk to the Commission and other parties as soon as possible. The Commission may wish to file an additional request for information after its review of the information contained on the disk. This being a technical error and not one of substance, any subsequent request for data can be answered, notwithstanding the procedural schedule in this case.

Sincerely,

James R. Goff

James R. Goff
Staff Attorney

JRG/v

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602
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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

August 30, 1999

Miss Bernice Cheeks
192 East Haiti Road
Berea, Kentucky 40403

Re: Case No. 99-176
Delta Natural Gas Company, Inc.

Dear Miss Cheeks:

The Commission has received your letter dated August 9 concerning the above case. Your letter is being treated as an official protest and will be placed in the case file. The Commission will carefully analyze this case before rendering its decision. Be advised that the effect of the rate increase cannot yet be determined as the increase originally proposed by Delta Natural Gas Company, Inc. is not necessarily what may be ordered in the Commission's final decision.

If you wish to participate in the proceeding, including any hearing that may be held, you must file a motion to intervene with the Commission. Attached is a copy of Commission regulations concerning intervention. If you request limited intervention and your request is granted, you will receive copies of all Commission Orders entered in this case. You will not, however, be served with filed testimony, exhibits, pleadings, correspondence or other documents submitted by the parties. If you wish such information, you must request and be granted full intervention. If you are granted intervention and wish to request a hearing, you should file such a request with Helen C. Helton, the Commission's Executive Director.

The Attorney General's Office for Rate Intervention, which represents consumers' interests has been granted intervention and is participating in this case. You may contact them at (502) 696-5453 to discuss their position on the issues you raise in your protest letter.

Thank you for your interest and concern in this matter.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

hv
Enclosure

EDUCATION PAYS

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

Adjustment of Rates of	)	
Delta Natural Gas Company, Inc.	)	Case No. 99-176

AUG 1 3 1999

NOTICE OF CORRECTION IN THE INITIAL
REQUESTS FOR INFORMATION BY THE ATTORNEY GENERAL

Notice is hereby given that in data requests numbers 84 and 86 erroneous reference is made to Case Number 99-070. The reference instead should be to Case Number 99-046, In re the Matter of Delta Natural Gas Company, Inc. Experimental Alternative Regulation Plan. The data requests should read as follows:

84. Please state whether the Company has made any changes to Original Sheet Nos. 30-35 of P.S.C. No. 9 contained in the tariff sheets filed in this proceeding compared to Original Sheet Nos. 30-35 of P.S.C. No. 8 filed in Case No. 99-046. If yes, please explain all such changes.

86. Please state whether the Company is aware of any changes which are necessary to its responses to the Attorney General's or the Commission's data requests in Case No. 99-046 with regard to the Company's proposed ARP. If yes, please identify the responses requiring modification and provide revised responses.

Respectfully Submitted,

E E Blackford

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5458

CERTIFICATE OF SERVICE AND OF FILING

I hereby certify that this the 13th day of August, 1999, I have filed the original and ten true copies of the foregoing with Hon. Helen C. Helton, Executive Director of the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky, 40601 and that I have served the parties by mailing the same, postage prepaid, to:

ROBERT M WATT III ESQ
STOLL KEENON & PARK LLP
201 EAST MAIN STREET
LEXINGTON KY 40507-1380

JOHN F HALL
DELTA NATURAL GAS COMPANY INC
3617 LEXINGTON ROAD
WINCHESTER KY 40391

JJ Blackford

99-176

AUG 1 1999

aug 9, 1999

Hi I saw your ~~ad~~ add in Papper about the fuel bill I don't Know if this means ~~gas~~ gas bill or Eletric bill. they are onley 1 of me in my houshole. the gas People send it way up there for 1 mounth & I onley heat 1 side of my house in the winter mounth. Please let me know if this about gas bill or Eletric bill. I do know for a back the bill is too hi. People all around me drewing disable & working ~~on~~ under the table theer gas bill are less then mind. I don't know how they do thing dis honesty & get by with it. I really have it rough in the winter mounth I sit around the house & keep my gas turned way down & it is still hi

Thanks Miss Bernice Cheeks

192 E Haiti Road
Berea Ky 40403 606-986-2322

P.S. over

I am 60 years old & Disable & I can't hardley make in meet. lot's of little kids go hungery & cold beause of the dis honesy people in the world

Thanks again

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

August 11, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

O R D E R

IT IS ORDERED that Delta Natural Gas Company, Inc. ("Delta") shall file the original and 12 copies of the following information with the Commission, with a copy to all parties of record, no later than August 23, 1999. Each copy of the information requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 Of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure its legibility. When the requested information has been previously provided in this proceeding or in Case No. 99-046[1] in the requested format, reference may be made to the specific location of that information in responding to this Order. When applicable, the requested information should be provided for total company operations and jurisdictional operations, separately.

[1] Case No. 99-046, Delta Natural Gas Company, Inc. Experimental Alternative Regulation Plan.

1. In Case No. 97-066-F,[2] Delta proposed to include its voluntary contributions to The Gas Research Institute ("GRI") in its gas cost adjustment ("GCA"). The Commission denied this request.

a. What is Delta's current position regarding GRI funding?

(1) Does Delta still propose that GRI funding should be recovered through the GCA mechanism?

(2) Is Delta proposing an alternative funding method for GRI as part of its rate case? If so, give details.

b. Is Delta aware that Western Kentucky Gas Company, in Case No. 99-070[3] presently pending before the Commission, has proposed a GRI tariff rider to recover those costs through a separate mechanism?

2. Reference testimony of John B. Brown and pages 36 and 37 of the proposed tariffs.

a. Will there be any time lag in the application of the Weather Normalization Adjustment ("WNA") tariff to customers' bills or is it a "real time" adjustment mechanism that will affect customers' bills for the month in which the consumption occurs?

b. Several formulas are included in the proposed tariff. Provide an example of the calculations, based on the formulas, that Delta will use to derive a customer's bill during the heating season when the WNA would be in effect.

[2] Case No. 97-066-F, Notice of Purchased Gas Adjustment Filing of Delta Natural Gas Company, Inc.

[3] Case No. 99-070, The Application of Western Kentucky Gas Company For An Adjustment of Rates.

c. The WNA for Columbia Gas of Kentucky was initially approved by the Commission as a pilot program. Has Delta given any consideration to proposing its WNA as a pilot? If not, why not?

3. Refer to testimony of Randall J. Walker.

a. Although the cost-of-service study supports an increase in the residential customer charge, Delta has proposed to keep the charge at the current level of $8 and apply the full amount of the increase proposed for the residential class to the commodity charge. Explain the reasoning for this rate design proposal.

b. Delta has applied a limitation to the increase for the residential class equal to 1.5 times the overall percentage increase requested. Was the choice of 1.5 entirely judgmental or were there quantifiable reasons for the choice of that ratio?

(1) Could the choice of 1.5 be characterized as arbitrary?

(2) Is there any more reason for 1.5 than 1.3, 1.4 or 1.6?

c. Refer to the significant differences in class rates of return. Has any consideration been given to whether the use of one basic rate schedule, the GS schedule, for all firm customers has contributed to the magnitude of these differences? Identify the advantages of maintaining one rate schedule for all firm customers. Identify any reasons why Delta would be opposed to establishing separate rate schedules for the different classes of customers presently served under the GS rate schedule.

4. The testimony of Robert C. Hazelrigg refers to having a difference of $.25 per Mcf between firm and interruptible rates in the proposed rates and that this was the difference prior to Delta's last rate case, Case No. 97-066. Are there specific reasons

for reverting to the $.25 difference? Why not $.20 or $.30 difference? Provide complete cost justification for the amount selected.

5. Refer to Delta's response to the Commission's data request dated July 15, 1999, Item 8, page 1 of 4. For the 12 months ended December 31, 1998, define the source of $527,243 shown as other income. If this is income from special charges, show in detail the income resulting from each charge.

6. Provide exhibits to the direct testimony of William Steven Seelye on electronic media, i.e., diskette, for the adjusted test year at current rates and proposed rates. In addition, if subsequent scenarios are filed, provide electronic versions.

7. Provide a reconciliation of your cost-of-service study and the testimony of John Hall.

8. Provide a reconciliation of the results of the cost-of-service study and the rate design prescribed by Randall J. Walker. Describe both similarities and variances.

9. a. Is the cost-of-service model as presented the result of a standard industry model? If so, provide source material and state why the selection of this model was made.

b. What other companies use this model?

c. What concerns or modifications have other state regulatory commissions expressed about the model presented in this case?

10. a. What other models were considered prior to selecting this model?

b. Did other models reviewed provide similar results and guidance?

c. If not, why was this model superior? If no other model was reviewed, how is this Commission assured that the guidance represented by this model is the most reasonable?

d. If not, how was this model selected and what assurance is made to Delta as to its reliability?

11. It is stated that the gas supply functional group was not utilized because the gas supply costs have been removed from the test-year operating results. Explain why this procedure was taken. How does this impact the results of the cost-of-service analyses?

12. Provide a list with associated results of internally generated functional vectors in a form comparable to those explicitly determined.

a. What is the basis for the explicitly determined vectors?

b. Were any other methods considered for determining the explicit vectors?

c. If so, why were they not chosen?

d. If not, how can it be assured that the best possible explicit vectors have been selected?

13. a. How were the allocation factors used in the study chosen?

b. Were any other methods for determining allocation factors considered?

c. If so, why were they not chosen?

d. If not, how can it be assured that the best possible allocation factors have been selected?

14. a. How were the cost-weighting factors determined for the customer accounts' allocation factor?

b. Were any other methods for determining these factors considered?

c. If so, why were they not chosen?

d. If not, how can it be assured that the best possible cost-weighting factors have been selected? Explain this process of weighting customer accounts.

15. The "zero intercept" method has been utilized in the preparation of this study. How is it superior to the "minimum system" approach?

16. a. Has a "minimum system" approach been evaluated in this proceeding?

b. If so, how do the results differ from those of the "zero intercept" approach?

17. Provide a revised Exhibit 5 utilizing the returns determined in Exhibit 2. How do the results match the rates proposed in this proceeding? If there are significant variances, explain why these variances occur and provide recommendations to move the proposed rates in the direction of diminishing variances.

18. a. Based upon the results contained in Exhibit 5, what would the proposed rates of Delta need to be?

b. Are these rates feasible?

c. Why or why not?

19. Provide all revisions to the testimony, schedules, and other supporting documentation, filed in Case No. 99-046 and incorporated into this proceeding,

necessary to update Delta's experimental alternative rate mechanism to the current test year proposed in Delta's current rate proceeding.

20. Explain Delta's position regarding how any approved rate adjustment and any approved alternative rate mechanism would be implemented at the time the Commission enters its final Order in the current proceeding.

21. If the Commission were to approve an alternative rate mechanism, similar to that which Delta proposes, at some point during Delta's budget cycle, would it be Delta's intention to implement the mechanism on the date of the Order, or would Delta desire to postpone implementation of the mechanism until the beginning of a new budget cycle? Fully explain and justify your response.

22. If Delta were to implement its alternative mechanism during an ongoing budget cycle, explain how the mechanism would be adjusted to reflect the passage of part of the budget cycle upon which the mechanism is based. Provide all supporting documentation and workpapers to support your response.

23. Provide copies of the workpapers, calculations, and other documentation to support each of Delta's proposed adjustments disclosed in the middle two columns of the balance sheet included in Item 38 of the application.

24. In Item 38 of its application, Delta made several adjustments to its balance sheet to "back out" its subsidiaries and Canada Mountain. Provide a revised balance sheet showing these adjustments separately for the subsidiaries and Canada Mountain.

25. Refer to Item 25 of Schedule 7 of the proposed rate base.

a. Explain why Delta has not allocated any of its prepayments, materials and supplies, gas in storage, unamortized debt, or advances for construction to any of Delta's subsidiaries.

b. Provide an explanation for Delta's adjustment of $541,248 to its unamortized debt. In the explanation, include documentation to support the 85.17 percent factor.

c. Delta's proposed rate base does not include construction work in progress ("CWIP") as a separate line item. Identify the amount of CWIP, if any, and the line item where it is included.

d. Provide all workpapers, calculations, and documentation necessary to support the $1,097,255 in total working capital.

26. In Delta's previous rate case, the Commission followed its historical precedent by adjusting rate base to reflect the 13-month average account balances for prepayments, materials and supplies, and gas in storage.

a. Explain why Delta used the end-of-period balances in its proposed rate base rather than the 13-month average balances.

b. Determine how the 13-month average balances for the above accounts would impact Delta's proposed rate base and revenue requirement. Include all workpapers, calculations, and assumptions used by Delta in its determination.

27. Refer to Delta's response to Item 12 of the Commission's July 15, 1999 Order.

a. Reconcile the $109,367,104 in the December 1998 balance for Account No. 101, Plant In Service, with the $114,965,626 in property, as reported in Item 25, Schedule 7, of the application.

b. Reconcile the $32,717,506 in the December 1998 balance for Account No. 10801, Depreciation Reserve, with the $35,230,946 in reserve for depreciation, as reported in Item 25, Schedule 7, of the application.

28. Refer to Item 38, Proposed Balance Sheet, of the application.

a. Reconcile the $112,470,779 in utility plant with the $114,965,626 in property, as shown in Item 25, Schedule 7, of the application.

b. Reconcile the $32,756,310 in accumulated provision for depreciation with the $35,230,946 in reserve for depreciation, as shown in Item 25, Schedule 7, of the application.

29. Refer to payroll adjustments, W/P 4-1, included in Item 25 of the application.

a. Reconcile the $5,893,686 in actual payroll with the $6,251,888, as shown in Item 25 of Schedule 6, as well as with the $6,175,661 in 1998 salaries and wages included in the response to Item 18(c) and the $5,952,002 total included in the response to Item 19, both of the Commission's July 15, 1999 Order. Include an explanation for each item included in the reconciliation.

b. Provide workpapers, calculations, and other documentation to support Delta's annualized payroll of $6,009,885. Delta's workpapers should identify each employee and position, the actual hours worked during the test period, the overtime hours worked during the test period, the wages effective prior to July 1, 1998, the wages effective July 1, 1998, and the percentage increase by employee.

30. Refer to Item 25, Schedule 4, of the application.

a. Provide detailed workpapers, calculations, and other documentation to support the following proposed adjustments.

(1)	Medical Adj.-Stop Loss	$ 77,561
(2)	New Customers Added	$ 54,498
(3)	Rate Case Cost	$145,000

b. Provide a breakdown, by account and amount, of the $121,120 adjustment to remove expenses related to the Canada Mountain project from the expenses includable for rate-making purposes.

c. Provide a breakdown, by account and amount, of the $142,711 adjustment to reflect the accounts disallowed in Case No. 97-066.

d. Has Delta included any of its proposed rate case cost of $145,000 in test-period operations and maintenance expenses?

e. On page 4 of his direct testimony, John F. Hall states that rate case expense will be amortized over 3 years; however, the amount of amortization requested on Schedule 4 appears to be based on a 5-year amortization period. Which rate case amortization period is correct?

31. Refer to WP51 included in Item 25 of the application.

a. Reconcile the $119,777,118 in utility plant as of December 31, 1997 with the $125,206,004 in utility plant per books on December 31, 1998 in Item 38 of the application.

b. Provide detailed workpapers, calculations, and other documentation used by Delta to arrive at the following depreciation adjustments.

(1)	Canada Mountain	\$463,710
(2)	Transportation Equipment	\$413,001
(3)	Power Operating Equipment	\$119,391
(4)	Tranex	\$126,144

32. Refer to Schedule 6 of Item 25 of the application.

a. Explain whether the payroll taxes totaling \$480,841 represent the payroll tax on total payroll or payroll tax on only the direct payroll of \$6251,888. Additionally, if the payroll tax is on total payroll, provide the payroll tax only on the direct payroll.

b. Provide detailed workpapers, calculations, or other documentation to support Delta's adjustment of \$47,147 to remove Canada Mountain's property taxes.

33. Refer to Schedule 8 of Item 25 of the application.

a. Provide detailed workpapers, calculations, and other documentation to support the \$973,775 in income tax book.

b. Reconcile the \$973,775 in income tax per books with the \$1,501,800 in book state and federal taxes, as reported on Schedule 2, included in the response to Item 21(a)(7) of the Commission's July 15, 1999 Order. Include an explanation for each item included in the reconciliation.

34. Describe the method of accounting for income taxes Delta is using for its financial statement purposes.

35. Refer to page 3 of 5 included in the response to Item 12 of the Commission's July 15, 1999 Order. Provide detailed workpapers, calculations, or other forms of documentation to support the determination of each separate component making up deferred taxes of $8,436,725.

36. Refer to Schedule 8 of Item 25 of the application. Delta's interest deduction of $3,114,019 is based on the debt levels and cost of debt as of the end of the test period; however, Delta has proposed to base its revenue requirement on rate base. Explain why Delta did not apply its weighted cost of debt to its rate base, as the Commission did in Case No. 97-066.

37. Refer to Schedule 9 of Item 25 of the application.

a. Provide a breakdown of the $13,580,916 adjustment to exclude Canada Mountain from Delta's capital structure. Reconcile the capital allocated to Deltran, Inc. ("Deltran") as identified in this breakdown with the rate base as calculated by Deltran in its most recently approved gas cost recovery filing.

b. Provide a breakdown, by subsidiary, of the $1,280,279 adjustment to exclude the subsidiaries from Delta's capital structure.

38. Refer to the response to Item 26(a) of the Commission's July 15, 1999 Order. Provide an analysis of the test-period billings for professional services to reflect the charges incurred for matters involving Delta's subsidiaries. Reconcile these charges to the proposed adjustment included in Item 25 of the application. For any sub-account for which an allocation was not reflected, provide a detailed explanation for not removing the entire amount from the operating expenses for rate-making purposes.

39. Refer to the response to Item 28 of the Commission's July 15, 1999 Order.

Provide all workpapers, calculations, and other documentation necessary to support the amount of its lobbyists' salaries Delta proposes to exclude from the test period.

40. Refer to the response to Item 29 of the Commission's July 15, 1999 Order.

a. Reconcile the balances in each of the accounts shown for the test period with the adjustments reflected in the balance sheet provided in Item 38 of the application.

b. Provide a detailed explanation for the changes in the following accounts:

(1) Net Plant Investment.

(2) Receivables from Others.

(3) Receivable from Parent.

(4) Taxes Payable.

(5) Revenues from Parent.

(6) Gas Costs.

(7) Expenses -- Other.

41. Refer to the response to Item 40 of the Commission's July 15, 1999 Order. Provide a breakdown of the "Other Compensation" column for 1998. This breakdown should include a description of the other compensation, the amounts, and the business reason for the compensation paid.

42. Refer to the response to Item 36 of the Commission's July 15, 1999 Order. Explain the reason Delta has not capitalized interest on construction.

43. Provide a detailed description, including all workpapers, calculations, and other necessary documentation, such as a cost allocation manual, of the allocation

methodologies used by Delta when making allocations (direct or indirect) to and from affiliated companies. Additionally, provide the total amount of these allocations, by account and subsidiary, for the test period and the 2 years preceding the test period.

44. Refer to page 19 of the 1998 Annual Report provided in Item 34 of the application.

a. Delta provides a non-contributory pension plan that covers all of its eligible employees. During the test period, did Delta make any contributions to the employee pension plan?

b. Provide a copy of Delta's most recent actuarial report concerning its employee pension plan.

c. Delta reported an accrued pension asset of $852,883 as of June 31, 1998. Provide Delta's December 31, 1998 accrued pension asset balance.

d. Provide a detailed explanation of why Delta did not propose to reduce its rate base by the balance in its accrued pension asset.

45. Provide a comparison of Delta's 1997, 1998, and 1999 employee health insurance premiums. The comparison should include the type of coverage provided, the total premium per employee, the amount of premium paid by the employee, the amount of the premium paid by Delta, and the percentage increase over the previous year's premium. Identify any measures Delta has implemented to control the rising health care insurance costs.

46. What impact would approval of the WNA tariff have on variability of revenue collections?

a. On earned return on equity?

b. On the cost of equity?

47. Refer to the response to Item 18 of the Commission's July 15, 1999 Order. Provide a detailed explanation for the variances in the following accounts. Also give a detailed analysis of any extraordinary charges included in the test-period totals.

a. 1856000 – Right of Way Clearing

b. 1880050 – Uniforms

c. 1881020 – Rent Land & Land Rights

d. 1900020 – Opr Transportation Expenses

e. 1903020 – Customer Collections & Records

f. 1904000 – Uncollectible Accounts

g. 1928000 – Regulatory Commission Expense

h. 1930020 – Company Memberships

i. 1930080 – Stockholder Reports

j. 1921060 – Miscellaneous Other Items

k. 1923010 – Outside Services Legal

l. 1923040 – Outside Services Other

m. 1408020 – Property Taxes

48. What impact does Delta's policy of providing 200 feet free on new extensions have on Delta's earned return on equity?

49. Refer to lines 11-15 of page 11 of Martin J. Blake's direct testimony. This indicates that Delta's payout history has had an adverse impact on Delta's ability to earn its allowed rate of return. Who sets Delta's payout ratio? What steps could be taken to adjust the payout ratio so that the return would not be negatively impacted?

50. Refer to Delta's response to Item 2 of the Commission's July 15, 1999 Order. During the 10-year period from 1988-1998, 1988 is the only year that Delta did not earn below the imputed 43.5 percent capital structure equity component proposed by Martin J. Blake. Explain why such a common equity component is reasonable in light of the fact that the test year common equity component is shown to be 31 percent.

51. Is Martin J. Blake's proposed leverage premium premised on the reasonableness of his proposed imputed capital structure?

52. Is Martin J. Blake aware of any state regulatory commissions applying a size premium or a leverage premium in determining the appropriate cost of equity for a regulated LDC?

53. Provide copies of the Hilliard Lyons, Edward Jones, and Ibbotson reports that are referenced in Exhibit MJB-4 of Martin J. Blake's direct testimony.

54. Provide the calculations that produce the rates of return set out on page 3 of Exhibit MJB-4 of Martin J. Blake's direct testimony.

55. Refer to the direct testimony of Martin J. Blake. Did Mr. Blake consider the impact of the alternative rate mechanism, as proposed by Delta, on Delta's required return on equity? Fully explain your response.

56. With regard to Delta's proposal to use a hypothetical capital structure,

a. Discuss the appropriateness of using a hypothetical capital structure when establishing a utility's revenue requirements when the utility is also proposing to implement an alternative rate mechanism that includes an incentive based on the utility's earned return on common equity.

b. Does Delta intend to modify its alternative rate mechanism to reflect the use of a hypothetical capital structure in establishing the utility's revenue requirements?

c. Explain how establishing rates, based on the hypothetical capital structure proposed by Delta, will impact the return on actual common equity and hence the functioning of the alternative rate mechanism proposed by Delta.

57. Refer to the response to Item 2 of the Commission's July 15, 1999 Order.

a. Provide Delta's average capital structure for the 10-year period of 1988 through 1998. Include all workpapers, calculations, and other forms of documentation used to perform the calculation.

b. Delta's common equity declined from 46.7 percent of total capital in 1988 to 40.8 percent in 1999. Provide a detailed explanation for the 5.9 percent decrease in the ratio of equity to total capital.

c. For the 10-year period between 1988 and 1998, Delta's equity has exceeded 40 percent of total capital only twice; however, on page 16 of his direct testimony, Martin J. Blake, recommends an imputed capital structure of 43.5 percent common equity and 56.5 percent debt. Given the historic trend in Delta's capital structure, how realistic is it to expect that Delta will achieve its imputed capital structure?

58. How does Delta intend to achieve its imputed capital structure of 43.5 percent common equity and 56.5 percent debt?

59. Refer to the February 1, 1999 letter provided in the response to Item 39 of the Commission's July 2, 1999 Order in Case No. 99-046. Provide copies of the following budget account worksheets referenced in Delta's letter:

a. Budgeted and actual amounts by month for fiscal year 1998.

b. Budget and actual amounts by month for calendar year 1998.

c. Budget amounts by month for fiscal year 1999.

60. Provide Delta's budgeted capital structure for 1999 and for 2000 when available.

61. Describe the impact Delta's imputed capital structure will have on its cost of debt.

62. Explain why Delta did not propose to adjust its cost of debt to reflect its imputed capital structure.

63. Refer to John Hall's direct testimony, "Other Proposed Tariff Changes," Exhibit 1, page 2 of 2, lines 24-26.

a. Define the term "gross negligence" as used in "Customer's Liability."

b. Explain why Delta wants to change its duty toward its customers.

64. Provide an analysis of the costs Delta has incurred to prepare its systems for the year 2000. This analysis should include a description of the service performed, stating whether the cost was expensed or capitalized, and the year the cost was incurred.

Done at Frankfort, Kentucky, this 11th day of August, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

CERTIFICATE OF SERVICE

RE: Case Nos. 99-046 and 99-176
DELTA NATURAL GAS COMPANY, INC.

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above cases was served upon the following by U.S. Mail on August 5, 1999.

Parties of Record:

John F. Hall
Vice President-Finance, Sec., Treasurer
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391

Honorable Robert M. Watt
Attorney at Law
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, Kentucky 40507-1380

Honorable Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601

Stephanie J. Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

DELTA NATURAL GAS COMPANY, INC. EXPERIMENTAL ALTERNATIVE REGULATION PLAN	)	CASE NO. 99-046
ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	)	CASE NO. 99-176

<u>ORDER</u>

Delta Natural Gas Company ("Delta") has moved for consolidation of the above styled proceedings. The Attorney General ("AG") has submitted a response in opposition to that motion. Having considered the motion and the response thereto, we deny the motion. Finding that Delta's application in Case No. 99-176 has rendered the proceedings in Case No. 99-046 moot, the Commission, on its own motion, dismisses Case No. 99-046.

On February 5, 1999, Delta filed with the Commission revised tariff sheets containing an experimental alternative regulation plan that establishes a rate mechanism that is designed to ensure Delta's recovery of revenues sufficient to achieve its authorized rate of return on equity. On March 5, 1999, the Commission initiated Case No. 99-046 to investigate the reasonableness of the proposed rate and suspended the proposed rate's operation for five months. We subsequently established a procedural schedule in this matter and directed Delta to publish notice of its proposed rate mechanism to its customers. On June 29, 1999, Delta submitted proof of publication.

On July 2, 1999, Delta filed an application for general adjustment of rates. In its application, Delta included revised tariff sheets set forth its proposed rates for natural gas service and for an experimental alternative regulation plan that differed significantly from the plan filed in Case No. 99-046.[1] Simultaneous with the filing of its application, Delta published notice of its proposed rate adjustment. In its notice, Delta stated:

> Delta Natural Gas Company, Inc. proposes the following **new tariffs**: Weather Normalization Adjustment Clause Applicable to General Service Rate Schedule and **Experimental Alternative Ratemaking Mechanism.**

Case No. 99-176, Application of Delta Natural Gas Company, Vol. 1, Section 9 (emphasis added). We docketed Delta's application for general rate adjustment as Case No. 99-176.

On July 6, 1999, Delta moved to consolidate Case No. 99-176 with Case No. 99-046 and to maintain the procedural scheduled established in Case No. 99-046. It provided no argument in support of its motion. Opposing the motion, the AG argues that adequate discovery of the proposed general rate adjustment cannot be conducted if the Commission adheres to the procedural schedule established in Case No. 99-046. He further suggests that, as the proposed experimental alternative regulation plan is part of the proposed general rate adjustment, any suspension of the proposed rates in Case No. 99-176 would include suspension of the experimental alternative regulation plan. Accordingly, the AG proposes that the Commission incorporate the record of

[1] The Commission acknowledges that Delta witness William Steven Seelye discussed the revised plan in his testimony in Case No. 99-046 and included revised tariff sheets that reflected these revisions. Delta, however, never moved for leave to amend its original filing nor did Delta formally submit revised tariff sheets amending its original filing. Accordingly, the revised plan was first filed with the Commission on July 2, 1999, when Delta filed its application for general rate adjustment.

Case No. 99-046 into Case No. 99-176 and dismiss Case No. 99-046. Delta contends that such action would violate KRS 278.190(3).[2]

After careful consideration, the Commission finds that the motion should be denied. Adequate review of Delta's proposed general rate adjustment cannot be conducted within the procedural schedule established in Case No. 99-046. The proposed general rate adjustment involves a host of issues unrelated to the experimental alternative regulation plan. Due process requires that all parties be afforded an adequate opportunity to conduct discovery and prepare their case. The procedural schedule in Case No. 99-046 does not provide this opportunity.

More importantly, Delta's actions have rendered the issues in Case No. 99-046 moot. With its application for general rate adjustment, Delta has proposed an experimental alternative regulation plan that differs significantly from its original proposal. To the extent that the plan contained in its general rate adjustment application is the more recent proposal, it must be considered as amending and superceding the earlier plan. The earlier plan, which is the subject of Case No. 99-046, has in effect become a nullity. Case No. 99-046, therefore, should be dismissed and removed from the Commission's docket. Any consideration of Delta's experimental alternative regulation plan shall be made in Case No. 99-176. The time requirements set forth in

---

2 At any hearing involving the rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the utility, and the commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible, and in any event not later than ten (10) months after the filing of such schedules.

KRS 278.190(3) for a Commission decision on the experimental alternative regulation plan must begin to run from the filing of Delta's application in Case No. 99-176.

IT IS THEREFORE ORDERED that:

1. Delta's Motion to Consolidate is denied.

2. Case No. 99-046 is dismissed and shall be removed from the Commission's docket.

Done at Frankfort, Kentucky, this 5th day of August, 1999.

By the Commission

ATTEST:

Helen C. Helton

Executive Director

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
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FRANKFORT, KY. 40602
(502) 564-3940

July 30, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	CASE NO. 99-176

ORDER

Delta Natural Gas Company, Inc. ("Delta") has applied for approval to adjust its rates for natural gas service and to establish an experimental alternative regulation plan. Finding that further proceedings are necessary to investigate the reasonableness of the proposed rates, the Commission by this Order suspends the operation of the proposed rates and proposed experimental alternative regulation plan for a period of five months.

IT IS THEREFORE ORDERED that:

1. The proposed rates and experimental alternative regulation plan set forth in Delta's application are suspended up to and including December 31, 1999.

2. The procedural schedule set forth in the Appendix to this Order shall be followed.

3. All requests for information and responses thereto shall be appropriately indexed. All responses shall include the name of the witness who will be responsible for responding to the questions related to the information provided, with copies to all parties of record and 10 copies to the Commission.

4. Delta shall give notice of the hearing in accordance with the provisions set out in 807 KAR 5:011, Section 8(5). At the time publication is requested, it shall forward a duplicate of the notice and request to the Commission.

5. At any hearing in this matter, neither opening statements nor summarization of direct testimony shall be permitted.

6. Motions for extensions of time with respect to the schedule herein shall be made in writing and will be granted only upon a showing of good cause.

7. All documents that this Order requires to be filed with the Commission shall be served upon all other parties by first class mail or express mail.

8. To be timely filed with the Commission, a document must be received by the Secretary of the Commission within the specified time for filing except that any document shall be deemed timely filed if it has been transmitted by United States express mail, or by other recognized mail carriers, with the date the transmitting agency received said document from the sender noted by the transmitting agency on the outside of the container used for transmitting, within the time allowed for filing.

9. Service of any document or pleading shall be made in accordance with Administrative Regulation 807 KAR 5:001, Section 3(7), and Kentucky Civil Rule 5.02.

10. The record of Case No. 99-046[1] is incorporated by reference into the record of this proceeding.

11. Nothing contained herein shall prevent the Commission from entering further Orders in this matter.

Done at Frankfort, Kentucky, this 30th day of July, 1999.

By the Commission

ATTEST:

Executive Director

[1] Case No. 99-046, Delta Natural Gas Company, Inc. Experimental Alternative Regulation Plan (filed February 5, 1999).

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-176 DATED JULY 30, 1999

All requests for information to Delta shall be served upon Delta no later than 08/11/99

Delta shall file with the Commission and serve upon all parties of record its responses to the requests for information no later than 08/23/99

All supplemental requests for information to Delta shall be served upon Delta no later than 09/03/99

Delta shall file with the Commission and serve upon all parties of record its responses to supplemental requests for information no later than 09/13/99

Intervenor testimony, if any, shall be filed with the Commission in verified prepared form no later than 09/23/99

All requests for information to any Intervenor shall be served upon that Intervenor no later than 10/04/99

Intervenors shall file with the Commission and serve upon all parties of record their responses to the requests for information no later than 10/14/99

Last day for Delta to publish notice of hearing date 10/21/99

Delta may file with the Commission the testimony of its rebuttal witnesses in written verified form no later than 10/25/99

Public Hearing is to begin at 9:00 a.m., Eastern Time, in Hearing Room 1 of the Commission's offices at 730 Schenkel Lane, Frankfort, Kentucky, for the purpose of cross-examination of witnesses of Delta and witnesses of the Intervenors 10/28/99

Parties may file written briefs with the Commission no later than 11/29/99

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Paul E. Patton
Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

July 28, 1999

Mr. Frank Cracraft
Ms. Dolly Cracraft
140 Prescott Road
Paris, KY 40361

RE: Case No. 99-176
Delta Natural Gas Company, Inc.

Dear Mr. and Ms. Cracraft:

The Commission has received your letter dated July 21 concerning the above case. Your letter is being treated as an official protest and will be placed in the case file. The Commission will carefully analyze this case before rendering its decision. Be advised that the effect of the rate increase cannot yet be determined as the increase originally proposed by Delta Natural Gas Company, Inc. is not necessarily what may be ordered in the Commission's final decision.

If you wish to participate in the proceeding, including any hearing that may be held, you must file a motion to intervene with the Commission. Attached is a copy of Commission regulations concerning intervention. If you request limited intervention and your request is granted, you will receive copies of all Commission Orders entered in this case. You will not, however, be served with filed testimony, exhibits, pleadings, correspondence or other documents submitted by the parties. If you wish such information, you must request and be granted full intervention. If you are granted intervention and wish to request a hearing, you should file such a request with Helen C. Helton, the Commission's Executive Director.

The Attorney General's Office for Rate Intervention, which represents consumers' interests has been granted intervention and is participating in this case. You may contact them at (502) 695-5453 to discuss their position on the issues you raise in your protest letter.

Thank you for your interest and concern in that matter.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

rlm
Enclosure

EDUCATION PAYS

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Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Helen Helton
Executive Director
Public Service Commission

July 28, 1999

Mrs. C. B. Ritchie
P.O. Box 91
North Middletown, KY 40357

RE: Case No. 99-176
Delta Natural Gas Company, Inc.

Dear Mrs. Ritchie:

The Commission has received your letter dated July 21 concerning the above case. Your letter is being treated as an official protest and will be placed in the case file. The Commission will carefully analyze this case before rendering its decision. Be advised that the effect of the rate increase cannot yet be determined as the increase originally proposed by Delta Natural Gas Company, Inc. is not necessarily what may be ordered in the Commission's final decision.

If you wish to participate in the proceeding, including any hearing that may be held, you must file a motion to intervene with the Commission. Attached is a copy of Commission regulations concerning intervention. If you request limited intervention and your request is granted, you will receive copies of all Commission Orders entered in this case. You will not, however, be served with filed testimony, exhibits, pleadings, correspondence or other documents submitted by the parties. If you wish such information, you must request and be granted <u>full</u> intervention. If you are granted intervention and wish to request a hearing, you should file such a request with Helen C. Helton, the Commission's Executive Director.

The Attorney General's Office for Rate Intervention, which represents consumers' interests has been granted intervention and is participating in this case. You may contact them at (502) 695-5453 to discuss their position on the issues you raise in your protest letter.

Thank you for your interest and concern in that matter.

Sincerely,

Stephanie Bell
Secretary of the Commission

rlm
Enclosure

EDUCATION PAYS

AN EQUAL OPPORTUNITY EMPLOYER M/F/D

99-176

140 Prescott Road
Paris, KY 40361
July 21, 1999

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JUL 26 1999

PUBLIC SERVICE
COMMISSION

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Public Service Commission
730 Schenkel Lane
P. O. Box 615
Frankfort, KY 40602

Dear Sir:

I read with interest and alarm the notice that was posted in the Bourbon County Newspaper that Delta Natural Gas Company, Inc has proposed a rate increase.

We who live in North Middletown have expressed concern over the increases we have experienced since Delta took over the provision of gas to our community. It appears that the rate has been raised about three times in the past four years.

Most of us who live in this community have been here for years and a good many of us are on very fixed income. We personally have air conditioning and if the gas rates continue to increase we are considering having our gas furnace replaced with electric heat, since we are able to be comfortable in the summer so much more economically than we can keep warm in the cold months.

We certainly appreciate the opportunity to express our opinion and would appreciate your considering our wishes and needs before granting this increase.

Thank you,

Dolly Cracraft
DOLLY CRACRAFT &

Frank S Cracraft
FRANK CRACRAFT

Mrs. C. B. Ritchie
Mrs. C. B. Ritchie
140 Prescott Road
Paris, KY
40361

Richie
P.O. Box 91
North Middletown
KY
40357

99-176

140 Prescott Road
Paris, KY 40361
July 21, 1999

Public Service Commission
730 Schenkel Lane
P. O. Box 615
Frankfort, KY 40602

RECEIVED

JUL 26 1999

PUBLIC SERVICE
COMMISSION

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40361

Richie
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North Middletown
KY
40357

STOLL, KEENON & PARK, LLP

201 EAST MAIN STREET
SUITE 1000
LEXINGTON, KENTUCKY 40507-1380

(606) 231-3000
FAX: (606) 253-1093

*FRANKFORT OFFICE:
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FRANKFORT, KY. 40601-1823
(502) 875-6220
FAX: (502) 875-6235

**WESTERN KENTUCKY OFFICE:
201 C NORTH MAIN STREET
HENDERSON, KY. 42420-3103
(502) 831-1900
FAX: (502) 827-4060

***LOUISVILLE OFFICE:
2650 AEGON CENTER
400 WEST MARKET
LOUISVILLE, KY. 40202-3377
(502) 568-9100
FAX: (502) 568-5700

INTERNET: www.skp.com

RECEIVED
JUL 13 1999
PUBLIC SERVICE
COMMISSION

July 13, 1999

Hon. Helen Helton
Executive Director
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40602

Re: Delta Natural Gas Company, Inc.
Case No. 99-046 and Case No. 99-176

Dear Ms. Helton:

We deliver herewith for filing an original and ten (10) copies of Delta's Reply in Further Support of its Motion to Consolidate and to Maintain Case No. 99-046 Procedural Schedule in the above-captioned cases. We would appreciate your placing the Reply with the other papers in the cases and bringing it to the attention of the Commission. Thank you for your kind assistance.

Sincerely,

Robert M. Watt, III

rmw
encl.
cc: Counsel of Record (w/encl.)
Mr. John F. Hall (w/ encl.)

RECEIVED

JUL 1 3 1999

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

DELTA NATURAL GAS COMPANY, INC. EXPERIMENTAL ALTERNATIVE REGULATION PLAN	)))	**CASE NO. 99-046**

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	))	**CASE NO. 99-176**

* * * * * * * * * * * *

REPLY IN FURTHER SUPPORT OF MOTION TO CONSOLIDATE AND TO MAINTAIN CASE NO. 99-046 PROCEDURAL SCHEDULE

Delta Natural Gas Company, Inc. ("Delta") respectfully submits this Reply in further support of its motion to consolidate Case No. 99-176, *In the Matter of: An Adjustment of Rates of Delta Natural Gas Company, Inc.*, into Case No. 99-046, *In the Matter of: Delta Natural Gas Company, Inc. Experimental Alternative Regulation Plan.* The Attorney General has filed a Response to the motion to consolidate in which he objects to the adoption of the procedural schedule ordered in Case No. 99-046 and suggests that Commission may simply incorporate the record in Case No. 99-046 into the record of Case No. 99-176 and dismiss Case No. 99-046. Delta objects to such procedure because the Commission does not have the authority to extend the date for a decision in Case No. 99-046 beyond December 5, 1999, which is ten months after the filing of Case No. 99-046. KRS 278.190(3). In fact, rather than extend the date for a decision in Case No. 99-046, Delta would withdraw its motion to consolidate which was made in an effort to proceed more efficiently in both cases.

Delta does not object to minor modifications to the Case No. 99-046 procedural schedule to permit sufficient time to conduct the necessary activities for Case No. 99-176, as long as the date for the decision does not occur after December 5, 1999. Delta reminds the Commission, however, that much of the discovery normally requested in general rate cases has already been requested by the Attorney General in Case No. 99-046. Thus, if any modifications are made to the procedural schedule, they should, indeed, be minor.

Respectfully submitted,

STOLL, KEENON & PARK LLP

Robert M. Watt, III
201 East Main Street, Suite 1000
Lexington, KY 40507
606) 231-3000

Counsel for Delta Natural Gas Company, Inc.

CERTIFICATE OF SERVICE

This is to certify that the foregoing pleading has been served by mailing a copy of same, postage prepaid, to the following persons on this 13th day of July 1999:

Gerald Wuetcher, Esq.
Public Service Commission
730 Schenkel Lane
P.O. Box 615
Frankfort, KY 40601

Elizabeth E. Blackford, Esq.
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601-8204

Robert Watt

Robert M. Watt, III

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

RECEIVED
JUL - 9 1999
PUBLIC SERVICE COMMISSION

In the Matter of:

An Adjustment of Rates of Delta Natural Gas Company, Inc.	))	Case No. 99-176

MOTION TO INTERVENE

Comes the Attorney General, A. B. Chandler, III, pursuant to KRS 367.150 (8) which grants him the right and obligation to appear before regulatory bodies of the Commonwealth of Kentucky to represent the consumers' interests, and moves the Public Service Commission to grant him full intervener status in this action pursuant to 807 KAR 5:001(8).

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
1024 CAPITAL CENTER DRIVE
FRANKFORT KY 40601
(502) 696-5453
FAX: (502) 573-4814

CERTIFICATE OF SERVICE AND OF FILING

I hereby Certify that this the 8th day of July, 1999, I have filed the Original and ten copies of the foregoing Motion with the Public Service Commission at 730 Schenkel Lane, Frankfort, KY, 40601, and that I have served the parties of record by mailing a true copy of same postage prepaid to:

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt, III
Stoll, Keenon & Park, LLP
201 East Main Street Suite 1000
Lexington, KY. 40507-1380

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
730 SCHENKEL LANE
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

July 15, 1999

John F. Hall
Vice President-Finance, Sec.,Treas.
Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, KY. 40391

Honorable Robert M. Watt
Stoll, Keenon & Park, LLP
201 East Main Street
Suite 1000
Lexington, KY. 40507 1380

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY. 40601

RE: Case No. 99-176

We enclose one attested copy of the Commission's Order in the above case.

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF RATES OF DELTA NATURAL GAS COMPANY, INC.	)) CASE NO. 99-176

ORDER

IT IS ORDERED that Delta Natural Gas Company, Inc. ("Delta") shall file with the Commission the original and 15 copies of the following information, with a copy to all parties of record. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 6. Include with each response the name of the witness who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been provided along with the original application, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. The information requested herein is due on or before July 29, 1999. When applicable, the information requested herein should be provided for total company operations and jurisdictional operations, separately.

1. Provide a copy of the current bylaws. Indicate any changes made to the bylaws since the year utilized as the test period in Delta's last rate case.

2. Provide the capital structure at the end of each of the periods as shown in Format 2.

3. a. Provide a list of all outstanding issues of long-term debt as of the end of the latest calendar year and the end of the test period together with the related information as shown in Format 3a. Provide a separate schedule for each time period. Report in Column (k) of Format 3a, Schedule 2, the actual dollar amount of debt cost for the test year. Compute the actual and annualized composite debt cost rates and report them in column (j) of Format 3a, Schedule 2.

b. Provide an analysis of end-of-period, short-term debt and a calculation of the average and end-of-period cost rate as shown in Format 3b.

4. Provide a list of all outstanding issues of preferred stock as of the end of the latest calendar year and the end of the test period as shown in Format 4. Provide a separate schedule for each time period. Report in Column (h) of Format 4, Schedule 2, the actual dollar amount of preferred stock cost accrued or paid during the test year. Compute the actual and annualized preferred stock cost rate and report the results in Column (g) of Format 4, Schedule 1.

5. a. List all issues of common stock in the primary market during the most recent 10-year period as shown in Format 5a.

b. Provide the common stock information on a quarterly and yearly basis for the most recent 5 calendar years available, and through the latest available quarter as shown in Format 5b.

c. Provide market prices for common stock for each month during the most recent 5-year period and for the months through the date the application is filed. List all stock splits and stock dividends by date and type.

6. Provide a computation of fixed charge coverage ratios for the 10 most recent calendar years and for the test year as shown in Format 6.

7. Provide the following:

a. A schedule of revenues for each active rate schedule reflecting test-year revenues per book rates, revenues at present rates annualized, and revenues at proposed rates annualized.

b. A schedule showing the amount and percent of any proposed increase or decrease in revenue distributed to each rate schedule. This schedule is to be accompanied by a statement which explains, in detail, the methodology or basis used to allocate the requested increase or decrease in revenue to each of the respective customer classes.

c. A schedule showing how the increase or decrease in (b) above was further distributed to each rate charge (i.e., customer or facility charge, Mcf charge, etc.). This schedule is to be accompanied by a statement which explains, in detail, the methodology or basis used to allocate the increase or decrease.

8. Provide, in comparative form, a total company income statement, a statement of changes in financial position, a statement of cash flows, a statement of changes in owner's equity, and a balance sheet for the test year and the 12-month period immediately preceding the test year.

9. Provide a trial balance as of the last day of the test year (all income statement accounts should show activity for 12 months) showing account number, account title, and amount. Provide this information on a total company operations

basis. Only one copy need be supplied to the Commission. Other parties of record may examine the copy filed with the Commission.

10. Provide the balance in each current asset and each current liability account and subaccount included in Delta's chart of accounts by months for the test year. In addition, show total current assets, total current liabilities, and the net current position by months, annually, and the 13-month average for the test year. Provide a reconciliation of current assets, current liabilities, and net current position provided in response to the above with the current assets and current liabilities as shown on the balance sheet for each month of the test year. If any amounts were allocated, provide a calculation of the factor used to allocate each amount.

11. List each common general office account (asset, reserve, and expense accounts) covering the 12 months of the test year applicable to more than one jurisdiction or utility operation. If any amounts were allocated, show a calculation of the factor used to allocate each amount.

12. Provide the following monthly account balances and a calculation of the average (13-month) account balances for the test year for the total company operations:

a. Plant in service (Account No. 101).

b. Plant purchased or sold (Account No. 102).

c. Property held for future use (Account No. 105).

d. Construction work in progress (Account No. 107).

e. Completed construction not classified (Account No. 106).

f. Depreciation reserve (Account No. 108).

g. Plant acquisition adjustment (Account No. 114).

h. Amortization of utility plant acquisition adjustment (Account No. 115).

i. Materials and supplies (include all account and subaccounts).

j. Balance in accounts payable applicable to each account in (i) above. (If actual is indeterminable, give reasonable estimate.)

k. Unamortized investment credit – Pre-Revenue Act of 1971.

l. Unamortized investment credit – Revenue Act of 1971.

m. Accumulated deferred income taxes.

n. A summary of customer deposits as shown in Format 12(n) to this request.

o. Computation and development of minimum cash requirements.

p. Balance in accounts payable applicable to amounts included in utility plant in service. (If actual is indeterminable, give reasonable estimate.)

q. Balance in accounts payable applicable to prepayments by major category or subaccount.

r. Balance in accounts payable applicable to amounts included in plant under construction. (If actual is undeterminable, give reasonable estimate.)

13. Provide the cash account balances at the beginning of the test year and at the end of each month during the test year for the total company.

14. Provide the following information for each item of gas plant held for future use at the end of the test year.

a. Description of property.

b. Location.

c. Date purchased.

d. Cost.

e. Estimated date to be placed in service.

f. Brief description of intended use.

g. Current status of each project.

15. Provide schedules, in comparative form, showing by months for the test year, and the year preceding the test year, the total company balance in each gas plant and reserve account or subaccount included in Delta's chart of accounts as shown in Format 15.

16. Provide the journal entries relating to the purchase of gas utility plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise since Delta's inception. Also, provide a schedule showing the calculation of the acquisition adjustment at the date of purchase or each item of utility plant, the amortization period, and the unamortized balance at the end of the test year.

17. Provide a schedule showing a comparison of the balance in the total company and Kentucky revenue accounts for each month of the test year to the same month of the preceding year for each revenue account or subaccount included in Delta's chart of accounts. Include appropriate footnotes to show the month each rate increase was granted and the month the full increase was recorded in the accounts. See Format 15.

18. Provide the following:

a. A schedule showing a comparison of the balance in the total company operating expense accounts for each month of the test year to the same month of the preceding year for each account or subaccount included in Delta's chart of accounts. See Format 15.

b. A schedule, in comparative form, showing the total company operating expense account balance for the test year and each of the 5 years preceding the test year for each account or subaccount included in Delta's annual report. (FERC Form No. 2, pages 320-325.) Show the percentage of increase of each year over the prior year.

c. A schedule of total company salaries and wages for the test year and each of the 5 calendar years preceding the test year as shown in Format 18c. Show for each time period the amount of overtime pay.

d. A schedule showing the percentage of increase in salaries and wages for both union and non-union employees for the test year and the 5 preceding years.

19. Provide the following payroll information for each employee classification or category:

a. The actual regular hours worked during the test year.

b. The actual overtime hours worked during the test year.

c. The test-year-end wage rate for each employee classification or category and the date of the last increase.

d. A calculation of the percent of increase granted during the test year.

20. Provide the amount of excess deferred federal income taxes resulting from the reduction in the corporate tax rate from 48 percent to 46 percent in 1979, as of the end of the test year.

21. Provide the following tax data for the test year for total company:

a. Income taxes:

(1) Federal operating income taxes deferred – accelerated tax depreciation.

(2) Federal operating income taxes deferred – other (explain).

(3) Federal income taxes - operating.

(4) Income credits resulting from prior deferrals of federal income taxes.

(5) Investment tax credit net.

i) Investment credit realized.

ii) Investment credit amortized – Pre-Revenue Act of 1971.

iii) Investment credit amortized – Revenue Act of 1971.

(6) The information in Item 21(a)(1-4) for state income taxes.

(7) A reconciliation of book to taxable income as shown in Format 21(a)(7) and a calculation of the book federal and state income tax expense for the test year using book taxable income as the starting point.

(8) A copy of federal and state income tax returns for the taxable year ended during the test year, including supporting schedules.

(9) A schedule of franchise fees paid to cities, towns, or municipalities during the test year, including the basis of these fees.

b. An analysis of Kentucky other operating taxes as shown in Format 21(b).

22. Provide a schedule of total company net income, per Mcf sold, per company books for the test year and the 5 calendar years preceding the test year. This data should be provided as shown in Format 22.

23. Provide the comparative operating statistics as shown in Format 23.

24. Provide a statement of gas plant in service, per company books, for the test year. This data should be presented as shown in Format 24.

25. Provide the following information. If any amounts were allocated, show a calculation of the factor used to allocate each amount.

a. A detailed analysis of all charges booked during the test period for advertising expenditures. Include a complete breakdown of Account 913 – Advertising Expenses, as shown in Format 25a showing any other advertising expenditures included in any other expense accounts. The analysis should specify the purpose of the expenditure and the expected benefit to be derived.

b. An analysis of Account No. 930 – Miscellaneous General expenses for the test period. Include a complete breakdown of this account as shown in Format 25b and provide detailed workpapers supporting this analysis. At a minimum, the workpapers should show the date, vendor, reference (i.e., voucher no., etc.), dollar amount, and brief description of each expenditure of $500 or more, provided that lesser items are grouped by classes as shown in Format 25b.

c. An analysis of Account No. 426 – Other Income Deductions for the test period. Include a complete breakdown of this account as shown in Format 25c, and provide detailed workpapers supporting this analysis. At a minimum, the workpapers should show the date, vendor, reference (i.e., voucher no., etc.), dollar amount, and brief description of each expenditure of $500 or more, provided that lesser items are grouped by classes as shown in Format 25c.

26. Provide a detailed analysis of expenses incurred during the test year for professional services, as shown in Format 26, and all workpapers supporting the analysis. At a minimum, the workpapers should show the payee, dollar amount, reference (i.e., voucher no., etc.), account charged, hourly rates and time charged to the company according to each invoice, and a description of the service provided.

27. Provide a detailed analysis of contributions for charitable and political purposes (in cash or services), if any, recorded in accounts other than Account No. 426. Show the amount of the expenditure, the recipient of the contribution, and the specific account charge. If amounts are allocated, show a calculation of the factor used to allocate each amount. Detailed analysis is not required for amounts of less than $100, provided the items are grouped by classes.

28. Describe Delta's lobbying activities and provide a schedule showing the name, salary, affiliation, all company-paid or reimbursed expenses or allowances and the account charged for all personnel whose principal function is lobbying on the local, state, or national level. If any amounts are allocated, show a calculation of the factor used to allocated each amount.

29. Provide a schedule showing for the test year and the year preceding the test year, with each year shown separately, the following information regarding Delta's investments in subsidiaries and joint ventures:

a. Name of subsidiary or joint venture.

b. Date of initial investment.

c. Amount and type of investment made for each of the 2 years included in this report.

d. Balance sheet and income statement. Where only internal statements are prepared, furnish copies of these.

e. A separate schedule of all dividends or income of any type received by Delta from its subsidiaries or joint ventures showing how this income is reflected in the reports filed with the Commission and stockholder reports.

f. Name of officers of each of the subsidiaries or joint ventures, officer's annual compensation, and portion of compensation charged to the subsidiary or joint venture and the position each officer holds with Delta and the compensation received from Delta.

30. Provide the following information with regard to uncollectible accounts for the test year and 5 preceding calendar years (taxable year acceptable) for total company:

a. Reserve account balance at the beginning of the year.

b. Charges to reserve account (accounts charged off).

c. Credits to reserve account.

d. Current year provision.

e. Reserve account balance at the end of the year.

f. Percent of provision to total revenue.

31. Provide a detailed analysis of the retained earnings account for the test period and the 12-month period immediately preceding the test period.

32. Provide a listing of all non-utility property, related property taxes, and accounts where amounts are recorded. Include a description of the property, the date purchased, and the cost.

33. Provide rates of return in Format 33.

34. Provide employee data in Format 34.

35. Provide the studies for the test year, including all applicable workpapers, which are the basis of jurisdictional plant allocations and expense account allocations.

36. Provide a calculation of the rate or rates used to capitalize interest during construction for the test year and the 3 preceding calendar years. Explain each component entering into the calculation of this rate.

37. Provide any information, when known, which would have a material effect on net operating income, rate base, or cost of capital which have occurred after the test year but were not incorporated in the filed testimony and exhibits.

38. Provide detailed monthly income statements for each month after the test period, including the month in which the hearing ends, as they become available.

39. List all present or proposed research efforts dealing with the pricing of gas and the current status of such efforts.

40. Provide a schedule reflecting the salaries and other compensation of each executive officer for the test year and the 2 preceding calendar years. Include the

percentage annual increase and the effective date of each increase, the job title, duty and responsibility of each officer, the number of employees who report to each executive officer, and to whom each executive officer reports. Also, for employees elected to executive officer status during the test year, provide the salaries, for the test year, for those persons whom they replaced.

41. Provide an analysis of Delta's expenses for research and development activities for the test year and the 5 preceding calendar years. For the test year include the following:

a. Basis of fees paid to research organizations and Delta's portion of the total revenue of each organization. Where the contribution is monthly, provide the current rate and the effective date.

b. Details of the research activities conducted by each organization.

c. Details of services and other benefits provided to the company by each organization during the test year and the preceding calendar year.

d. Total expenditures of each organization including the basic nature of costs incurred by the organization.

e. Details of the expected benefits to the company.

42. Provide the average number of customers for each customer class (i.e., residential, commercial, and industrial) for the 5 calendar years preceding the test period, the test period, and for each month of the test period.

43. Provide all current labor contracts and the most recent contracts previously in effect.

44. Provide a detailed analysis of all benefits provided to the employees of Delta. For each benefit include:

a. The number of employees covered at test-year end.

b. The test-year actual cost.

c. The amount of the test-year actual cost capitalized and expensed.

d. The average annual cost per employee.

45. Provide complete details of the financial reporting and rate-making treatment of Delta's pension costs.

46. Provide complete details of Delta's financial reporting and rate-making treatment of Statement of Financial Accounting Standard ("SFAS") No. 106, including:

a. The date that Delta adopted SFAS No. 106.

b. All accounting entries made at the date of adoption.

c. All actuarial studies and other documents used to determine the level of SFAS No. 106 cost recorded by Delta.

47. Provide complete details of Delta's financial reporting and rate-making treatment of SFAS No. 112, including:

a. The date that Delta adopted SFAS No. 112.

b. All accounting entries made at the date of adoption.

c. All actuarial studies and other documents used to determine the level of SFAS No. 112 cost recorded by Delta.

48. Provide the following information concerning the costs for the preparation of this case:

a. A detailed schedule of expenses incurred to date for the following categories:

(1) Accounting;

(2) Engineering;

(3) Legal;

(4) Consultants;

(5) Other Expenses (Identify separately).

For each category, the schedule shall include the date of each transaction, check number or other document reference, the vendor, the hours worked, the rates per hour, amount, a description of the services performed, and the account number in which the expenditure was recorded. Provide copies of any invoices, contracts, or other documentation which support charges incurred in the preparation of this rate case. Indicate any costs incurred for this case that occurred during the test year.

b. An itemized estimate of the total cost to be incurred for this case. Expenses shall be broken down into the same categories as identified in (a) above, with an estimate of the hours to be worked and the rates per hour. Include a detailed explanation of how the estimate was determined, along with all supporting workpapers and calculations.

c. During the course of this proceeding, provide monthly updates of the actual costs incurred, in the manner requested in (a) above. Updates will be due the last business day of each month, through the month of the public hearing.

49. Provide a copy of Delta's most recent depreciation study. If no such study exists, provide a copy of Delta's most recent depreciation schedule, including: a list of

all pipeline and related facilities by account number; service life and accrual rate for each; the methodology which supports the schedule; and the date the schedule was last updated.

Done at Frankfort, Kentucky, this 15th day of July, 1999.

By the Commission

ATTEST:

Executive Director

Format 2
Schedule 1

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176

Comparative Capital Structures (Excluding JDIC)
For the Periods as Shown
"000 Omitted"

Line No.	Type of Capital	10th Year		9th Year		8th Year		7th Year		6th Year		5th Year	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1.	Long-Term Debt												
2.	Short-Term Debt												
3.	Preferred & Preference Stock												
4.	Common Equity												
5.	Other (Itemize by type)												
6.	Total Capitalization												

Line No.	Type of Capital	4th Year		3rd Year		2nd Year		1st Year		Test Year		Latest Available Quarter		Average Test Year	
		Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
1.	Long-Term Debt														
2.	Short-Term Debt														
3.	Preferred & Preference Stock														
4.	Common Equity														
5.	Other (Itemize by type)														
6.	Total Capitalization														

Instructions:
1. Provide a calculation of the average test year data as shown in Format 1, Schedule 2.
2. If the applicant is a member of an affiliated group, the above data is to be provided for the parent company and the system consolidated.

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Calculation of Average Test Period Capital Structure
12 Months Ended ____________

"000 Omitted"

Line No.	Item (a)	Total Capital (b)	Long-Term Debt (c)	Short-Term Debt (d)	Preferred Stock (e)	Common Stock (f)	Retained Earnings (g)	Total Common Equity (h)
1.	Balance Beginning of test year							
2.	1st Month							
3.	2nd Month							
4.	3rd Month							
5.	4th Month							
6.	5th Month							
7.	6th Month							
8.	7th Month							
9.	8th Month							
10.	9th Month							
11.	10th Month							
12.	11th Month							
13.	12th Month							
14.	Total (L1 through L13)							
15.	Average balance (L14 ÷ 13)							
16.	Average capitalization ratios							
17.	End-of-period capitalization ratios							

Instructions:
1. If applicable, provide an additional schedule in the above format excluding common equity in subsidiaries from the total company capital structure. Show the amount of common equity excluded.
2. Include premium on class of stock.

Format 3a
Schedule 1

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176

Schedule of Outstanding Long-Term Debt
For the Calendar Year Ended December 31, ____________

Line No.	Type of Debt Issue (a)	Date of Issue (b)	Date of Maturity (c)	Amount Outstanding (d)	Coupon Interest Rate[1] (e)	Cost Rate At Issue[2] (f)	Cost Rate to Maturity[3] (g)	Bond Rating at Time of Issue[4] (h)	Type of Obligation (i)	Annualized Cost Col.(d) x Col.(g) (j)
	Total Long-Term Debt and Annualized Cost									
	Annualized Cost rate [Total Col. (j) + Total Col. (d)]									

1 Nominal Rate

2 Nominal Rate Plus Discount or Premium Amortization

3 Nominal Rate Plus Discount or Premium Amortization and Issuance Cost

4 Standard and Poor's, Moody, etc.

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176

Schedule of Outstanding Long-Term Debt
For the Test Year Ended ________

Line No.	Type of Debt Issue (a)	Date of Issue (b)	Date of Maturity (c)	Amount Outstanding (d)	Coupon Interest Rate[1] (e)	Cost Rate at Issue[2] (f)	Cost Rate to Maturity[3] (g)	Bond Rating at Time of Issue[4] (h)	Type of Obligation (i)	Annualized Cost Col.(d)xCol.(g) (j)	Actual Test Year Interest Cost[5] (k)
Total Long-Term Debt and Annualized Cost											
Annualized Cost Rate [Total Col. (j) ÷ Total Col. (d)]											
Actual Long-Term Debt Cost Rate [Total Col. k ÷ Total Reported in Col. (c) Line 15 of Format 1, Schedule 2]											

1 Nominal Rate

2 Nominal Rate Plus Discount or Premium Amortization

3 Nominal Rate Plus Discount or Premium Amortization and Issuance Cost

4 Standard and Poor's, Moody, etc.

5 Sum of Accrued Interest Amortization of Discount or Premium and Issuance Cost

Format 3b

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Schedule of Short-Term Debt

For the Test Year Ended ____________

Line No.	Type of Debt Instrument (a)	Date of Issue (b)	Date of Maturity (c)	Amount Outstanding (d)	Nominal Interest Rate (e)	Effective Interest Cost Rate (f)	Annualized Interest Cost Col.(d)xCol.(f) (g)
	Total Short-Term Debt						
	Annualized Cost Rate [Total Col. (g) ÷ Total col. (d)]						
	Actual Interest Paid or Accrued on Short-Term Debt during the Test Year [Report in Col. (g) of this schedule]						
	Average Short-Term Debt - Format 1, Schedule 2 Line 15 Col. (d) [Report in Col. (g) of this schedule]						
	Test-Year Interst Cost Rate [Actual Interest ÷ Average Short-Term Debt] [Report in Col (f) of this schedule]						

1. In all instances where the Effective Interest Cost Rate is different from the Nominal Interest Rate provide a calculation of the effective Interest Cost Rate in sufficient detail to show the items of costs that cause the difference.

Format 4
Schedule 1

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Schedule of Outstanding Shares of Preferred Stock

For the Calendar Year Ended ____________

Line No.	Description of Issue (a)	Date of Issue (b)	Amount Sold (c)	Amount Outstanding (d)	Dividend Rate (e)	Cost Rate at Issue (f)	Annualized Cost Col.(f) x Col.(d) (g)	Convertibility Features (h)
Total								
Annualized Cost Rate [Total Col.(g) + Total Col.(d)]								

Instruction:

1. If the applicant has issued no preferred stock, this schedule may be omitted.

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Schedule of Outstanding Long-Term Debt

For the Calendar Year Ended December 31, ____________

Line No.	Description of Issue (a)	Date of Issue (b)	Amount Sold (c)	Amount Outstanding (d)	Dividend Rate (e)	Cost Rate at Issue (f)	Annualized Cost Col.(f) x Col.(d) (g)	Actual Test Year Cost (h)	Convertibility Features (i)
	Total								
	Annualized Cost Rate [Total Col. (g) ÷ Total Col. (d)]								
	Actual Test Year Cost Rate [Total Col. (h) ÷ Total Reported in Col. (e), Line 15 of Format 1, Schedule 2]								

Instruction:

1. If the applicant has issued no preferred stock, this schedule may be omitted.

Format 5a

DELTA NATURAL GAS COMPANY, INC.

Case No. 99-176

Schedule of Common Stock Issue

For the 5 Year Period Ended ____________

DATE OF			Number of Shares Issued	Price Per Share to Public	Price Per Share (Net to Company)	Book value Per Share At Date of Issue	Selling Exps. As % of gross Issue Amount	Net Proceeds to Company
Issue	Announcement	Registration						

Instructions:

1. If applicant is a member of an affiliate group, provide in a separate schedule the above data for the parent company.

Format 5b

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Quarterly and Annual Common Stock Information

For the Periods as Shown

Period Equity	Average No. of Shares Outstanding	Book Value	Earnings per Share	Dividend Rate Per Share	Return on Average Common
	(000)	($)	($)	($)	(%)
5th Calendar Year:					
1st Quarter					
2nd Quarter					
3rd Quarter					
4th Quarter					
Annual					
4th Calendar Year:					
1st Quarter					
2nd Quarter					
3rd Quarter					
4th Quarter					
Annual					
3rd Calendar Year:					
1st Quarter					
2nd Quarter					
3rd Quarter					
4th Quarter					
Annual					
2nd Calendar Year:					
1st Quarter					
2nd Quarter					
3rd Quarter					
4th Quarter					
Annual					
1st Calendar Year					
1st Quarter					
2nd Quarter					
3rd Quarter					
4th Quarter					
Annual					
Latest					

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Computation of Fixed Charge Coverage Ratios

For the Periods as Shown

	10th Calendar Year		9th Calendar Year		8th Calendar Year		7th Calendar Year		6th Calendar Year		5th Calendar Year	
No. Item	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement
Net Income												
Additions:												
Itemize												
Total Additions												
Deductions:												
Itemize												
Total Deductions												
Income Available for Fixed Charge Coverage												
Fixed Charges												
Fixed Charge Coverage Ratio												

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Computation of Fixed Charge Coverage Ratios

For the Periods as Shown

No. Item	4th Calendar Year		3rd Calendar Year		2nd Calendar Year		1st Calendar Year		Test Year	
	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement	Sec Method	Bond or Mortgage Indenture Requirement
Net Income										
Additions:										
Itemize										
Total Additions										
Deductions:										
Itemize										
Total Deductions										
Income Available for Fixed Charge Coverage										
Fixed Charges										
Fixed Charge Coverage Ratio										

Format 12n

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Summary of Customer Deposits

Test Year

Line No.	Month (a)	Receipts (b)	Refunds (c)	Balance (d)
1.	Balance Beginning of test year			
2.	1st Month			
3.	2nd Month			
4.	3rd Month			
5.	4th Month			
6.	5th Month			
7.	6th Month			
8.	7th Month			
9.	8th Month			
10.	9th Month			
11.	10th Month			
12.	11th Month			
13.	12th Month			
14.	Total (L1 through L13)			
15.	Average balance (L14 ~ 13)			
16.	Amount of deposits received during test period			
17.	Amount of deposits refunded during test period			
18.	Number of deposits on hand end of test year			
19.	Average amount of deposit (L15, Col.(d) ~ L18)			
20.	Interest paid during test period			

Format 15

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Comparison of Total Company Test Year Account Balances
With Those of the Preceding Year

"000 Omitted"

Account Title and Account Number	1st Month	2nd Month	3rd Month	4th Month	5th Month	6th Month	7th Month	8th Month	9th Month	10th Month	11th Month	12 Month	Total
Test Year													
Prior Year													
Increase													
(Decrease)													

DELTA NATURAL GAS COMPANY, INC.

CASE NO. 99-176

Analysis of Salaries and Wages
For the Calendar Years 19 Through 19
And the Test Year
(000's)

		12 Months Ended											
		Calendar Years Prior to Test Year										Test Year	
		5th		4th		3rd		2nd		1st			
Line No.	Item (a)	Amount (b)	% (c)	Amount (d)	% (e)	Amount (f)	% (g)	Amount (h)	% (i)	Amount (j)	% (k)	Amount (l)	% (m)
1.	Wages charged to expense:												
2.	Power production expense												
3.	Transmission expenses												
4.	Distribution expenses												
5.	Customer accounts expense												
6.	Sales expenses												
7.	Administrative and general expenses:												
	(a) Administrative and general salaries												
	(b) Office supplies and expense												
	(c) Administrative expense transferred-cr.												
	(d) Outside services employed												
	(e) Property insurance												
	(f) Injuries and damages												
	(g) Employees pensions and benefits												