CASE NUMBER:

99-176

filed 9.13.99 – 9.24.99

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September 24, 1999

VIA HAND DELIVERY

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

RECEIVED
SEP 24 1999
PUBLIC SERVICE COMMISSION

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

Dear Ms. Helton:

We deliver herewith for filing the original and 15 copies of the Response of Delta Natural Gas Company, Inc. to the Data Requests dated September 14, 1999, in the above-captioned case. We appreciate your placing the Response with the other papers in the case. Thank you for your kind assistance.

Sincerely,

J. Mel Camenisch, Jr.

JMC/das
Enclosures
(320)C:\Work\069\WBI\Helton Letter
cc: Counsel of Record (with enclosures)
John F. Hall (without enclosures)
Robert M. Watt III (without enclosures)

RECEIVED
SEP 24 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 FOR CONFIDENTIAL TREATMENT OF COMPUTER DISKETTE

Delta Natural Gas Company, Inc. ("Delta") respectfully moves the Commission, pursuant to 807 KAR 5:001, Section 7, for confidential treatment of the computer diskette responsive to Item 1 of the Commission's Order of September 14, 1999, herein. The diskette is attached hereto pursuant to 807 KAR 5:001, Section 7(2)(a).

The Commission should accord confidential treatment to the diskette because its disclosure would permit an unfair commercial advantage to competitors of The Prime Group, Delta's consultant herein. Specifically, the diskette contains a cost of service model prepared and owned by The Prime Group the details of which are confidential and proprietary to The Prime Group. The public availability of that information will place The Prime Group at a competitive disadvantage with those consultants which are not required to reveal such information publicly. The information on the diskette contains, among other things, secret commercially valuable formulae which are used by The Prime Group in preparing cost of service studies. The information is, therefore, protected from disclosure by KRS 61.878.

Because of the foregoing situation, Delta has not served a copy of the diskette upon the Attorney General pending the entry of the requested order for confidential treatment and the execution by the Attorney General, or a person authorized on his behalf, and any of the Attorney General's consultants having access to the information, of an agreement to maintain the confidentiality of the information on the computer diskette.

Respectfully submitted,

STOLL, KEENON & PARK, LLP

By_______________________

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 24th day of September 1999:

Elizabeth E. Blackford, Esq. (w/o diskette)
Assistant Attorney General
1024 Capital Center Drive
Frankfort, KY 40601-8204

____
Robert M. Watt, III

C:\Work\DELTA\99 Rates\Confidential Mtn 1

RECEIVED

SEP 24 1999

PUBLIC SERVICE
COMMISSION

Notes

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.

RESPONSE:

Delta has made a motion for the Commission to treat the attached computer diskette as confidential. See Delta's Motion for Confidential Treatment of Computer Diskette, which is attached separately.

The cost of service model is a proprietary program written in Excel Visual Basic for Applications ("Excel VBA"). The program was developed for the internal use of The Prime Group and was not designed for purposes of distribution outside of The Prime Group. As such, the program is not particularly "user friendly" (i.e., ergonomically designed).

Notes on using the program:

- The model must operate in Excel's manual calculation mode. To calculate or recalculate a spreadsheet within the workbook enter F9. In working with the Functional Assignment and Allocation worksheets (i.e., going back and forth between these two sheets) it will be necessary to recalculate the sheets using F9.

- After any changes are made to the Functional Assignment worksheet, enter "Ctrl c" to copy worksheet values to the FA Process Area worksheet. This must be done prior to recalculating the Allocation worksheet. Otherwise, the Allocation worksheet will not pick up any changes made to the Functional Assignment worksheet.

- The model uses two special functions written in VBA: "Functionalize" and "Allocate." The "Functionalize" special function is used to functionally assign and classify costs in the "Functional Assignment" worksheet. The form of this special function is

  = Functionalize (Range, Index)

  Where "Range" is the reference to the functional assignment vector.

  "Index" is the column offset from the total column

  The "Allocate" special function is used to allocate costs that have been functionally assigned and classified to the customer classes. The form of this special function is

  = Allocate (Range, Index)

Where "Range" is the reference to the allocation vector.

"Index" is the column offset from the total column

WITNESS: Steve Seelye

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

2. a. How will Delta's acquisition of the assets of Mt. Olivet Natural Gas Company ("Mount Olivet") affect Delta's revenues? Revise Application Schedules 24, 25 and 38 (and any other schedule deemed appropriate) to reflect the effects of the 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 of 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.

RESPONSE:

a. Delta has not included Mt. Olivet in this rate case as the Mt. Olivet acquisition has not been completed. Therefore, these adjustments are not known and measurable. It is estimated that rate base would increase by $475,445 and capital structure would increase by $475,000. Operating revenue would increase by $335,450. Operating expense would increase by $283,273. Thus, overall, decreasing Delta's revenue requirement by $8,311. See attached revised schedules.

b. See Attached

Sponsoring Witness:

John F. Hall (a)
Randall Walker (b)

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

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

GENERAL SERVICE - RESIDENTIAL

	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	389,608	$ 8.00	$ 3,116,864	$ 8.00	$ 3,116,864
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	2,188,737	$ 2.7212	5,955,991	$ 3.4682	7,590,978
next 800 Mcf /mo.		$ 2.5000		$ 1.8500	
next 4000 Mcf /mo.		$ 2.1000		$ 1.4500	
next 5000 Mcf /mo.		$ 1.5000		$ 1.0500	
over 10000 Mcf /mo.		$ 1.1000		$ 0.8500	
Calculated Billings at Base Rates	2,188,737		$ 9,072,855		$ 10,707,842
Correction Factor - (Calculated /Actual)		*1.00055*		*1.00055*	
Total After Application of Correction Factor			$ 9,067,870		$ 10,701,958
Temperature Normalization Adjustment					
first 200 Mcf /mo.	374,497	$ 2.7212	1,019,080	$ 3.4682	1,298,829
next 800 Mcf /mo.					
next 4000 Mcf /mo.					
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Year-End Customers Adjustment					
Customer Charges	829	$ 8.00	6,632	$ 8.00	6,632
first 200 Mcf /mo.	64,976	$ 2.7212	176,812	$ 3.4682	225,349
next 800 Mcf /mo.					
next 4000 Mcf /mo.					
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
	Mcf				
Total Adjusted Billings at Base Rates	2,628,210		$ 10,270,395		$ 12,232,769
GCR at Current Rates	2,628,210	$ 3.7706	9,909,927	$ 3.7706	9,909,927
Total Adjusted Billings			$ 20,180,322		$ 22,142,696
Proposed Increase In Revenue					$ 1,962,374
					9.72%

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

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

GENERAL SERVICE - SMALL COMMERCIAL

	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	49,417	$ 18.36	$ 907,296	$ 17.00	$ 840,089
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	535,842	$ 2.7212	1,458,133	$ 3.4682	1,858,407
next 800 Mcf /mo.	14,975	$ 2.5000	37,438	$ 1.8500	27,704
next 4000 Mcf /mo.	2,852	$ 2.1000	5,989	$ 1.4500	4,135
next 5000 Mcf /mo.		$ 1.5000		$ 1.0500	
over 10000 Mcf /mo.		$ 1.1000		$ 0.8500	
Calculated Billings at Base Rates	553,669		$ 2,408,856		$ 2,730,335
Correction Factor - (Calculated /Actual)		*0.99959*		*0.99959*	
Total After Application of Correction Factor			$ 2,409,837		$ 2,731,447
Temperature Normalization Adjustment					
first 200 Mcf /mo.	90,387	$ 2.7212	245,961	$ 3.4682	313,480
next 800 Mcf /mo.	2,526	$ 2.5000	6,315	$ 1.8500	4,673
next 4000 Mcf /mo.	481	$ 2.1000	1,010	$ 1.4500	698
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Year-End Customers Adjustment					
Customer Charges	228	$ 18.36	4,186	$ 17.00	3,876
first 200 Mcf /mo.	34,672	$ 2.7212	94,350	$ 3.4682	120,250
next 800 Mcf /mo.	969	$ 2.5000	2,422	$ 1.8500	1,793
next 4000 Mcf /mo.	185	$ 2.1000	388	$ 1.4500	268
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Total Adjusted Billings at Base Rates	682,889		$ 2,764,469		$ 3,176,484
GCR at Current Rates	682,889	$ 3.7706	2,574,901	$ 3.7706	2,574,901
Total Adjusted Billings			$ 5,339,370		$ 5,751,385
Proposed Increase In Revenue					$ 412,015
					7.72%

Calculation of Proposed Rate Increase
In Response to PSC Order dated Sep. 14, 1999 - Item 2

Schedule 24 of Filing
and Walker Exhibit 7

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

GENERAL SERVICE - LARGE COMMERCIAL & INDUSTRIAL

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	10,644	$ 25.00	$ 266,100	$ 50.00	$ 532,200
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	682,110	$ 2.7212	1,856,158	$ 3.4682	2,365,694
next 800 Mcf /mo.	373,671	$ 2.5000	934,178	$ 1.8500	691,291
next 4000 Mcf /mo.	340,474	$ 2.1000	714,995	$ 1.4500	493,687
next 5000 Mcf /mo.	130,445	$ 1.5000	195,668	$ 1.0500	136,967
over 10000 Mcf /mo.	146,358	$ 1.1000	160,994	$ 0.8500	124,404
Calculated Billings at Base Rates	1,673,058		$ 4,128,092		$ 4,344,244
Correction Factor - (Calculated /Actual)		*1.00007*		*1.00007*	
Total After Application of Correction Factor			$ 4,127,796		$ 4,343,933
Temperature Normalization Adjustment					
first 200 Mcf /mo.	87,159	$ 2.7212	237,176	$ 3.4682	302,283
next 800 Mcf /mo.	40,096	$ 2.5000	100,240	$ 1.8500	74,178
next 4000 Mcf /mo.	25,791	$ 2.1000	54,161	$ 1.4500	37,397
next 5000 Mcf /mo.	7,921	$ 1.5000	11,881	$ 1.0500	8,317
over 10000 Mcf /mo.	8,078	$ 1.1000	8,885	$ 0.8500	6,866
Year-End Customers Adjustment					
Customer Charges	2	$ 25.00	50	$ 50.00	100
first 200 Mcf /mo.	1,482	$ 2.7212	4,032	$ 3.4682	5,139
next 800 Mcf /mo.	(397)	$ 2.5000	(993)	$ 1.8500	(735)
next 4000 Mcf /mo.	(243)	$ 2.1000	(510)	$ 1.4500	(352)
next 5000 Mcf /mo.	41	$ 1.5000	61	$ 1.0500	43
over 10000 Mcf /mo.					
Total Adjusted Billings at Base Rates	1,842,984		$ 4,542,780		$ 4,777,168
GCR at Current Rates	1,097,390	$ 3.7706	4,137,819	$ 3.7706	4,137,819
Total Adjusted Billings			$ 8,680,598		$ 8,914,987
Proposed Increase In Revenue					$ 234,388
					2.70%

Calculation of Proposed Rate Increase
In Response to PSC Order dated Sep. 14, 1999 - Item 2

Schedule 24 of Filing
and Walker Exhibit 7

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

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

	INTERRUPTIBLE SERVICE - COMMERCIAL & INDUSTRIAL				
	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	527	$ 200.00	$ 105,400	$ 250.00	$ 131,750
	Mcf	*per Mcf*		*per Mcf*	
first 1000 Mcf /mo.	412,084	$ 1.7000	700,543	$ 1.6000	659,334
next 4000 Mcf /mo.	780,789	$ 1.3000	1,015,026	$ 1.2000	936,947
next 5000 Mcf /mo.	178,298	$ 0.9000	160,468	$ 0.8000	142,638
over 10000 Mcf /mo.	60,144	$ 0.5000	30,072	$ 0.6000	36,086
Calculated Billings at Base Rates	1,431,315		$ 2,011,509		$ 1,906,756
Correction Factor - (Calculated /Actual)		*0.99946*		*0.99946*	
Total After Application of Correction Factor			$ 2,012,600		$ 1,907,791
Temperature Normalization Adjustment					
first 1000 Mcf /mo.	4,213	$ 1.7000	7,161	$ 1.6000	6,740
next 4000 Mcf /mo.	1,220	$ 1.3000	1,586	$ 1.2000	1,464
	Mcf				
Total Adjusted Billings at Base Rates	1,436,748		$ 2,021,347		$ 1,915,995
GCR at Current Rates	45,238	$ 3.7706	170,573	$ 3.7706	170,573
Total Adjusted Billings			2,191,920		$ 2,086,568
Proposed Increase In Revenue					$ (105,353)
					-4.81%

DELTA NATURAL GAS COMPANY INC
Cost of Service – Revenue Requirement
Test Period Ended 12/31/98

Line No			
1	Cost of Gas	Schedule 3	$16,793,220
2	Operations & Maintenance Expense	Schedule 4	$ 8,830,204
3	Depreciation Expense	Schedule 5	$ 3,597,642
4	Taxes Other Than Income Taxes	Schedule 5	$ 1,189,201
5	Return	Schedule 7	$ 7,129,734
6	Income Tax	Schedule 8	$ 2,592,250
7	Total Cost of Service		$40,132,251
8	Revenues at Present Rates	Schedule 2	$37,628,765
9	Revenue Deficiency		$ 2,503,486

Delta Natural Gas Company, Inc.
Case No. 99-176
Revised Summary of Proposed Rate Increase by Rate Class
In Response to PSC Data Request Dated Sep. 14, 1999 (Item 2)

	Actual Billed Revenue	Elimination of GCR Revenues	Current Rates for Full Year and Rate Switching	Net Before Temperature and Year-End Adjustments	Temperature Normalization Adjustment	Year-End Customers	Inclusion of Mount Olivet	Adjusted Billings @ Base Rates	GCR @ Current Charges	Adjusted Billings @ Current Rates	Proposed Increase in Revenue	Percentage Increase
REVENUE							*(1)*	*(1)*		*(1)*		
General Service									$ 3.7706			
Residential	18,296,074	(9,431,520)	42,919	8,907,472	1,019,080	183,444	160,398	10,270,395	9,909,927	20,180,322	1,962,374	9.72%
Commercial - Small	4,845,419	(2,446,952)	11,370	2,409,837	253,286	101,346		2,764,469	2,574,901	5,339,370	412,015	7.72%
Lg. Commercial & Industrial												
Retail Sales	6,944,686	(4,208,243)	17,227	2,753,670	337,794	2,640		3,094,104	4,137,820	7,231,924		
Transportation	1,469,977		(95,851)	1,374,126	74,550			1,448,676		1,448,676		
Total Lg. Com. & Ind.	8,414,662	(4,208,243)	(78,623)	4,127,796	412,344	2,640		4,542,780	4,137,820	8,680,600	234,388	2.70%
Total General Service	31,556,155	(16,086,716)	(24,334)	15,445,105	1,684,711	287,430		17,577,644	16,622,647	34,200,292	2,608,777	7.63%
Interruptible Service												
Retail Sales	254,214	(173,321)		80,893	8,747			89,640	170,573	260,213		
Transportation	1,931,707			1,931,707				1,931,707		1,931,707		
Total Interruptible Service	2,185,922	(173,321)		2,012,600	8,747			2,021,347	170,573	2,191,920	(105,353)	-4.81%
Special Contracts	511,666		104,167	615,833		16,689		632,522		632,522		
Off-System Transportation	451,990			451,990				451,990		451,990		
Total Sales and Transportation	34,705,733	(16,260,037)	79,833	18,525,529	1,693,458	304,119		20,683,504	16,793,220	37,476,724	2,503,424	6.68%
Miscellaneous Service Revenues	152,009			152,009				152,009		152,009		
Total Gas Operating Revenue	34,857,742	(16,260,037)	79,833	18,677,538	1,693,458	304,119		20,835,513	16,793,220	37,628,733	2,503,424	6.65%
MCF												
General Service							*(1)*	*(1)*				
Residential	2,142,320			2,142,320	374,497	64,976	46,417	2,628,210				
Commercial - Small	553,669			553,669	93,394	35,826		682,889				
Lg. Commercial & Industrial												
Retail Sales	966,462			966,462	130,046	882		1,097,390				
Transportation	756,019		(49,423)	706,596	38,998			745,594				
Total Lg. Com. & Ind.	1,722,481		(49,423)	1,673,058	169,044	882		1,842,984				
Total General Service	4,418,470		(49,423)	4,369,047	636,935	101,684		5,154,083				
Interruptible Service												
Retail Sales	39,805			39,805	5,433			45,238				
Transportation	1,391,510			1,391,510				1,391,510				
Total Interruptible Service	1,431,315			1,431,315	5,433			1,436,748				
Special Contracts	1,755,567		49,423	1,804,990		12,286		1,817,276				
Off-System Transportation	1,404,111			1,404,111				1,404,111				
Total Sales and Transportation	9,009,463		-	9,009,463	642,367	113,970		9,812,218				

1. *See attached supporting worksheet and Revised Schedule 24 filed pursuant to this request.*

Delta Natural Gas Company, Inc.

Revenues at Present Rates with Inclusion of Mount Olivet
Response to PSC Order dated Sep. 14, 1999 - Item 2

	Delta Natural Gas Company, Inc. (As Filed)	Mount Olivet	Total
Customer-Mos.	385,336	4,272	389,608
Mcf			
first 200 Mcf /mo.	2,142,320	46,417	2,188,737
Customer Charge		$ 8.00	
Base Rate per Mcf		$ 2.7212	
GCR per Mcf		$ 3.7706	
Customer Charge Billings		$ 34,176	
Commodity Billings		126,310	
Sub-Total		$ 160,486	
Correction Factor		*1.00055*	
Additional Base Rate Revenue		$ 160,398	
Additional GCR Revenue		175,020	
Total		$ 335,418	
Residential			
Base Rate Revenue	10,109,997	160,398	10,270,395
GCR Revenue	9,734,907	175,020	9,909,927
Total	19,844,904	335,418	20,180,322
Total Company			
Base Rates	20,675,115	160,398	20,835,513
GCR	16,618,200	175,020	16,793,220
Total	37,293,315	335,418	37,628,733

DELTA NATURAL GAS COMPANY INC
O & M Adjustments
Test Year Ended 12/31/98

Line No.				
1	Adjustments to Payroll			116,199
2	Accounts Disallowed in Case No. 97-066			(142,711)
3	Remove Canada Mtn			(120,120)
5	Rate Case Expense		145,000	29,000
6	Customer Deposits	6%	594,863	35,692
7	Medical Adj-Stop Loss			77,561
8	New Customers Added			54,498
9	Total O & M Adjustments			50,119
10	O & M Per Books			8,727,918
11	O & M Adjusted			8,778,037
12	Mt. Olivet O & M			52,167
13	O & M Adjusted			8,830,204

DELTA NATURAL GAS COMPANY INC
Depreciation Adjustment
Test Year Ended 12/31/98

Line No		
1	Depreciated Expense	3,550,142
2	Per Books	3,570,354
3	Adjustment	(20,212)
4	Add Mt. Olivet Depreciation & Amortization	47,500
5	Adjustment	27,288
6	Per Books	3,570,354
		3,597,642

DELTA NATURAL GAS COMPANY
Payroll Tax Adjustment
Test Year Ended 12/31/98

Payroll Tax and Property Tax Adjustment

Line No		
1	Direct Total Payroll for 12 Months Ended 12/31/98	6,251,888
2	Payroll Taxes (A/C # 1.408.03)	480,841
3	Payroll Taxes Percent of Payroll	7.69%
4	Payroll Increase	116,119
5	Payroll Tax Increase	8,937
6	Remove Canada Mt. Property Taxes	(47,147)
7	Total Adjustment to Taxes Other Than Income Taxes	(38,210)
8	Taxes Other than Income Taxes @ 12/31/98	1,223,848
9	Taxes Other than Income Taxes Adjusted	1,185,638
10	Add Mt. Olivet	3,563
11	Taxes Other than Income Taxes Adjusted	1,189,201

DELTA NATURAL GAS COMPANY INC
Rates Base and Return
Test Year Ended 12/31/98

Rate Base: Line No				
1	Property			114,965,626
2	Less Reserve for Depreciation			(35,230,946)
3	Net Plant			79,734,680
4	Working Capital			1,103,776
5	Prepayments			106,884
6	Materials and Supplies, at Cost			451,812
7	Gas in Storage, at Cost			265,579
8	Accumulated Provision for Deferred Income Taxes			(8,436,725)
9	Unamortized Debt	3,650,173	85.17%	3,108,925
10	Advances for Construction			(220,060)
11	Mt. Olivet Net Plant & Acquisition Adjustment			475,000
12	Depreciation Adjustment			(27,288)
13	Total Rate Base			76,562,583
14	Return @ 9.3123%			7,129,734

DELTA NATURAL GAS COMPANY INC
Income Tax Adjustment
Test Year Ended 12/31/98

Line No			
1	INCOME TAX ADJUSTMENT		
2	Net Income Books		1,705,196
3	Income Tax Books		973,775
4	Taxable Income/Books		2,678,971
5	LESS ADJUSTMENTS		
6	Rev & Gas Costs		13,847,177
7	Oper Exp		15,236,529
8	Adjusted Income Before Taxes		4,068,323
9	Adjusted Income Tax at	39.445%	1,604,750
10	Income Tax Books		973,775
11	As Adjusted		630,975
12	Adjusted Income Taxes @ 12/31/98		1,604,750
13	Income Taxes on Revenue Deficiency		987,500
14	Total Income Taxes		2,592,250

DELTA NATURAL GAS COMPANY INC
Interest Costs Adjustment
Test Year Ended 12/31/98

Interest Costs Adjustment

Line No		AMOUNT	RATE	INTEREST
1	Long Term Debt	$37,161,228	7.4786%	$ 2,779,121
2	Short Term Debt	$ 6,190,353	5.4100%	$ 334,898
3				$ 3,114,019
4				
5	Interest per Books			$ 4,509,474
6	Adjustment Required			$ (1,395,455)
7	Mt. Olivet Interest			$ 23,145
8	Adjustment			$ (1,372,310)

INCOME STATEMENT:

	Per Books	Increase ---Adjustments to test period--- Revenues	Expenses	Income Taxes	Adjusted Test Period	Increase Required	Adjusted For Increase
Net Operating Revenues	34,857,742	(13,847,177)			21,010,565	2,503,486	23,514,051
Operating Expenses							
Gas Purchased	14,147,177	0	(13,972,157)		175,020		175,020
Operations & Maintenance	8,727,918	0	102,286		8,830,204		8,830,204
Depreciation	3,570,354		27,288		3,597,642		3,597,642
Other Taxes	1,223,848	0	(34,647)		1,189,201		1,189,201
Income Taxes	973,775		13,011	630,975	1,604,750	987,500	2,592,250
Total	28,643,072	0	(13,864,219)	630,975	15,396,817	987,500	16,384,317
Operating Income	6,214,670	(13,847,177)	(13,864,219)	630,975	5,613,748	1,515,986	7,129,734
	0	0			0		0
Interest on Debt	4,509,474		(1,372,310)		3,137,164		3,137,164
Amort of Debt Expense	0				0		0
Total Debt Expense	4,509,474	0	(1,372,310)		3,137,164		3,137,164
Net Income	1,705,196	(13,847,177)	(15,236,529)	630,975	2,476,584	1,515,986	3,992,570

ASSETS	Per Books 12/31/98	Backout Subs & Canada Mtn	Proposed Adjustment	Proposed	Add Mt Olivet	Proposed Including Mt Olivet
UTILITY PLANT	125,206,004	-14,323,170	1,587,945	112,470,779		
Less-Accumulated provision				0		
for depreciation	-33,478,352	742,254	-20,212	-32,756,310		
Net utility plant	91,727,652	-13,580,916	1,567,733	79,714,469	475,000	
CURRENT ASSETS						
Cash	422,379		674,876	1,097,255		
Accounts receivable - net	1,781,108		-1,781,108	0		
Deferred gas cost	1,354,892		-1,354,892	0		
Gas in storage	3,364,903		-3,099,324	265,579		
Materials and supplies	451,812			451,812		
Prepayments	106,884			106,884		
Total current assets	7,481,978		-5,560,448	1,921,530		
OTHER ASSETS						
Cash surrender value of						
officers' life insurance	347,789		-347,789	0		
Unamortized debt	3,650,173		-541,248	3,108,925		
Invest in subs	1,466,060	-1,280,279	-185,781	0		
Other	1,049,138		-1,049,138	0		
Total other assets	6,513,160	-1,280,279	-2,123,956	3,108,925		
Total assets	105,722,790	-14,861,195	-6,116,671	84,744,924		
LIABILITIES AND SHAREHOLDERS' EQUITY						
CAPITALIZATION						
Common shareholders' equity	28,351,812	-5,484,286	10,509,355	33,376,881		
Long-term debt	54,207,845	-8,037,940	-9,008,680	37,161,225		
Total capitalization	82,559,657	-13,522,226	1,500,675	70,538,106	475,000	
CURRENT LIABILITIES						
Notes payable	9,030,000	-1,338,969	-2,140,998	5,550,033		
Current portion of long-ter	0			0		
Accounts payable	1,749,573		-1,749,573	0		
Accrued taxes	-441,509		441,509	0		
Refunds due customers	72,839		-72,839	0		
Customers' deposits	594,864		-594,864	0		
Accrued interest on debt	1,220,198		-1,220,198	0		
	0		0	0		
Other current and accrued						
liabilities	881,858		-881,858	0		
Total current liabiliti	13,107,823	-1,338,969	-6,218,821	5,550,033		
DEFERRED CREDITS AND OTHER						
Deferred income taxes	8,436,725		0	8,436,725		
Investment tax credits	602,550		-602,550	0		
Regulatory liability	795,975		-795,975	0		
Advances for construction a	220,060		0	220,060		
Total deferred credits	10,055,310		-1,398,525	8,656,785		
	105,722,790	-14,861,195	-6,116,671	84,744,924		

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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?

RESPONSE:

The advantage to both Delta and its customers for continuing to recover the costs of Canada Mountain through the GCR rather than through base rates is that the GCR provides for a full reconciliation of the actual costs of Canada Mountain through the application of the Actual Adjustment and Balance Adjustment. Therefore, under the current procedure of collecting these costs through the GCR, Delta will not over- or under collect costs associated with Canada Mountain.

However, at this point in the rate case, the concept of rolling Canada Mountain costs into base rates raises some thorny costs allocation and customer equity issues. Delta has not prepared a cost of service study that considers the allocation of Canada Mountain costs. From the point of view of customer equity, perhaps the best approach is to allocate these costs to the customer groups on the basis of the dollar amounts currently being recovered from customers through the GCR. This methodology, which is the approach that we have presented in our response to item 5, has the advantage of preserving, as nearly as possible, the current recovery of Canada Mountain revenue requirement through the GCR. However, another approach would be to allocate the Canada Mountain revenue requirement to the customer groups on the basis of the winter season sales volumes. The advantage of this approach is that it might do a better job of reflecting how storage related costs would be allocated in the cost of service study.

Sponsoring Witness:

Steve Seelye
Randall Walker

[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).

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

4. Explain why Delta did not propose in this proceeding to include the recovery of Canada Mountain in its base rates.

RESPONSE:

Delta did not propose to include the recovery of Canada Mountain costs in base rates because Delta thought it would complicate the case without significantly altering the overall recovery of costs.

Sponsoring Witness:

John F. Hall

Notes

5

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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 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 operation 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. Described the effect on Delta's GCR if the Commission determined that the costs of Canada Mountain facilities should be recovered through base rates.

RESPONSE:

a. Rate base would increase by $13.714,018. Capital structure would increase by $13,580,916. Operating revenues would not change. Operating expense would increase by $165,281. Thus, overall, increasing Delta's revenue requirement by $2,344,113. See attached revised schedules.

c. See attached.

d. The effect on Delta's GCR would be a reduction of $2,395,489 as approved in Case No. 97-066-F. See Delta's response to item 3 as to why it is still in the best interest of Delta's customers to permit recovery of Canada Mountain costs through Delta's GCR rather than through general rates.

Sponsoring Witness:

John F. Hall (a) & (d)
Randall Walker (c)

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

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

	GENERAL SERVICE - RESIDENTIAL				
	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	385,336	$ 8.00	$ 3,082,688	$ 8.00	$ 3,082,688
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	2,142,320	$ 2.7212	5,829,681	$ 4.0167	8,605,057
next 800 Mcf /mo.		$ 2.5000		$ 2.2810	
next 4000 Mcf /mo.		$ 2.1000		$ 1.4500	
next 5000 Mcf /mo.		$ 1.5000		$ 1.0500	
over 10000 Mcf /mo.		$ 1.1000		$ 0.8500	
Calculated Billings at Base Rates	2,142,320		$ 8,912,369		$ 11,687,745
Correction Factor - (Calculated /Actual)		*1.00055*		*1.00055*	
Total After Application of Correction Factor			$ 8,907,472		$ 11,681,323
Temperature Normalization Adjustment					
first 200 Mcf /mo.	374,497	$ 2.7212	1,019,080	$ 4.0167	1,504,241
next 800 Mcf /mo.					
next 4000 Mcf /mo.					
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Year-End Customers Adjustment					
Customer Charges	829	$ 8.00	6,632	$ 8.00	6,632
first 200 Mcf /mo.	64,976	$ 2.7212	176,812	$ 4.0167	260,989
next 800 Mcf /mo.					
next 4000 Mcf /mo.					
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
	Mcf				
Total Adjusted Billings at Base Rates	2,581,793		$ 10,109,997		$ 13,453,185
GCR at Current Rates	2,581,793	$ 3.7706	9,734,907	$ 3.2271	8,331,703
Total Adjusted Billings			$ 19,844,904		$ 21,784,887
Proposed Increase In Base Rate Revenue					$ 3,343,187
Proposed Overall Increase In Revenue					$ 1,939,983
Overall Percentage Increase					9.78%

Calculation of Proposed Rate Increase
In Response to PSC Order dated Sep. 14, 1999 - Item 5

Schedule 24 of Filing
and Walker Exhibit 7

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

GENERAL SERVICE - SMALL COMMERCIAL

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	49,417	$ 18.36	$ 907,296	$ 17.00	$ 840,089
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	535,842	$ 2.7212	1,458,133	$ 4.0167	2,152,317
next 800 Mcf /mo.	14,975	$ 2.5000	37,438	$ 2.2810	34,158
next 4000 Mcf /mo.	2,852	$ 2.1000	5,989	$ 1.4500	4,135
next 5000 Mcf /mo.		$ 1.5000		$ 1.0500	
over 10000 Mcf /mo.		$ 1.1000		$ 0.8500	
Calculated Billings at Base Rates	553,669		$ 2,408,856		$ 3,030,699
Correction Factor - (Calculated /Actual)		*0.99959*		*0.99959*	
Total After Application of Correction Factor			$ 2,409,837		$ 3,031,933
Temperature Normalization Adjustment					
first 200 Mcf /mo.	90,387	$ 2.7212	245,961	$ 4.0167	363,057
next 800 Mcf /mo.	2,526	$ 2.5000	6,315	$ 2.2810	5,762
next 4000 Mcf /mo.	481	$ 2.1000	1,010	$ 1.4500	698
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Year-End Customers Adjustment					
Customer Charges	228	$ 18.36	4,186	$ 17.00	3,876
first 200 Mcf /mo.	34,672	$ 2.7212	94,350	$ 4.0167	139,268
next 800 Mcf /mo.	969	$ 2.5000	2,422	$ 2.2810	2,210
next 4000 Mcf /mo.	185	$ 2.1000	388	$ 1.4500	268
next 5000 Mcf /mo.					
over 10000 Mcf /mo.					
Total Adjusted Billings at Base Rates	682,889		$ 2,764,469		$ 3,547,071
GCR at Current Rates	682,889	$ 3.7706	2,574,901	$ 3.2271	2,203,750
Total Adjusted Billings			$ 5,339,370		$ 5,750,822
Proposed Increase In Base Rate Revenue					$ 782,602
Proposed Overall Increase In Revenue					$ 411,452
Overall Percentage Increase					7.71%

Calculation of Proposed Rate Increase
In Response to PSC Order dated Sep. 14, 1999 - Item 5

Schedule 24 of Filing
and Walker Exhibit 7

Delta Natural Gas Company, Inc.

Case No. 99-176

GENERAL SERVICE - LARGE COMMERCIAL & INDUSTRIAL

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	10,644	$ 25.00	$ 266,100	$ 50.00	$ 532,200
	Mcf	*per Mcf*		*per Mcf*	
first 200 Mcf /mo.	682,110	$ 2.7212	1,856,158	$ 4.0167	2,739,831
next 800 Mcf /mo.	373,671	$ 2.5000	934,178	$ 2.2810	852,344
next 4000 Mcf /mo.	340,474	$ 2.1000	714,995	$ 1.4500	493,687
next 5000 Mcf /mo.	130,445	$ 1.5000	195,668	$ 1.0500	136,967
over 10000 Mcf /mo.	146,358	$ 1.1000	160,994	$ 0.8500	124,404
Calculated Billings at Base Rates	1,673,058		$ 4,128,092		$ 4,879,434
Correction Factor - (Calculated /Actual)		*1.00007*		*1.00007*	
Total After Application of Correction Factor			$ 4,127,796		$ 4,879,084
Temperature Normalization Adjustment					
first 200 Mcf /mo.	87,159	$ 2.7212	237,176	$ 4.0167	350,090
next 800 Mcf /mo.	40,096	$ 2.5000	100,240	$ 2.2810	91,459
next 4000 Mcf /mo.	25,791	$ 2.1000	54,161	$ 1.4500	37,397
next 5000 Mcf /mo.	7,921	$ 1.5000	11,881	$ 1.0500	8,317
over 10000 Mcf /mo.	8,078	$ 1.1000	8,885	$ 0.8500	6,866
Year-End Customers Adjustment					
Customer Charges	2	$ 25.00	50	$ 50.00	100
first 200 Mcf /mo.	1,482	$ 2.7212	4,032	$ 4.0167	5,952
next 800 Mcf /mo.	(397)	$ 2.5000	(993)	$ 2.2810	(906)
next 4000 Mcf /mo.	(243)	$ 2.1000	(510)	$ 1.4500	(352)
next 5000 Mcf /mo.	41	$ 1.5000	61	$ 1.0500	43
over 10000 Mcf /mo.					
Total Adjusted Billings at Base Rates	1,842,984		$ 4,542,780		$ 5,378,049
GCR at Current Rates	1,097,390	$ 3.7706	4,137,819	$ 3.2271	3,541,387
Total Adjusted Billings			$ 8,680,598		$ 8,919,436
Proposed Increase In Base Rate Revenue					$ 835,269
Proposed Overall Increase In Revenue					$ 238,837
Overall Percentage Increase					2.75%

Calculation of Proposed Rate Increase
In Response to PSC Order dated Sep. 14, 1999 - Item 5

Schedule 24 of Filing
and Walker Exhibit 7

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

Calculated Increase In Revenue under Proposed Revision of Rates (Based on the adjusted sales for the 12-mos. ended December 31, 1998)

INTERRUPTIBLE SERVICE - COMMERCIAL & INDUSTRIAL

	Billing Determinants	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed Rates
	Cust.	*per Cust.*		*per Cust.*	
Customer Charges	527	$ 200.00	$ 105,400	$ 250.00	$ 131,750
	Mcf	*per Mcf*		*per Mcf*	
first 1000 Mcf /mo.	412,084	$ 1.7000	700,543	$ 1.6000	659,334
next 4000 Mcf /mo.	780,789	$ 1.3000	1,015,026	$ 1.2000	936,947
next 5000 Mcf /mo.	178,298	$ 0.9000	160,468	$ 0.8000	142,638
over 10000 Mcf /mo.	60,144	$ 0.5000	30,072	$ 0.6000	36,086
Calculated Billings at Base Rates	1,431,315		$ 2,011,509		$ 1,906,756
Correction Factor - (Calculated /Actual)		*0.99946*		*0.99946*	
Total After Application of Correction Factor			$ 2,012,600		$ 1,907,791
Temperature Normalization Adjustment					
first 1000 Mcf /mo.	4,213	$ 1.7000	7,161	$ 1.6000	6,740
next 4000 Mcf /mo.	1,220	$ 1.3000	1,586	$ 1.2000	1,464
	Mcf				
Total Adjusted Billings at Base Rates	1,436,748		$ 2,021,347		$ 1,915,995
GCR at Current Rates	45,238	$ 3.7706	170,573	$ 3.2271	145,986
Total Adjusted Billings			2,191,920		$ 2,061,981
Proposed Increase In Base Rate Revenue					$ (105,353)
Proposed Overall Increase In Revenue					$ (129,939)
Overall Percentage Increase					-5.93%

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

	Proposed Rate As Filed	Canada Mountain	Proposed Rate As Revised
General Service			
first 200 Mcf /mo.	3.4787	0.5380	4.0167
next 800 Mcf /mo.	1.8500	0.4310	2.2810
next 4000 Mcf /mo.	1.4500	-	1.4500
next 5000 Mcf /mo.	1.0500	-	1.0500
over 10000 Mcf /mo.	0.8500	-	0.8500

	Reduced GCR Amount (Can. Mtn.)	%	Filed Base Rate Increase	*target amt.* Base Rate Increase applicable to (Can. Mtn.)	*target amt.* Total Base Rate Increase Including (Can. Mtn.)	*Actual amt.* Achieved
Residential	(1,403,204)	0.59187	1,954,816	1,387,948	3,342,764	$ 3,343,187
Small Commercial	(371,150)	0.15655	418,957	367,115	786,072	$ 782,602
Large Commercial/Industrial	(596,431)	0.25158	242,481	589,947	832,428	$ 835,269
Interruptible	(24,587)		(105,353)		(105,353)	$ (105,353)
Total Sales	(2,395,372)		2,510,901	2,345,009	4,855,910	$ 4,855,706
Firm Sales	(2,370,786)	1.00000		2,345,009		

WORKSHEET TO APPORTION CANADA MOUNTAIN COSTS THAT ARE CURRENTLY RECOVERED THROUGH THE GCR MECHANISM INTO THE BASE RATES

Delta Natural Gas Company, Inc

GCR Revenues @ May 1, 1999 GCR Rate
With and Without Canada Mountain Costs Included
Response to PSC Order dated Sep. 14, 1999 - Item 5

	May 1, 1999 GCR Rate Including Canada Mtn. Costs As Approved by PSC		May 1, 1999 GCR Rate Excluding Canada Mtn. Costs	Difference
EGC Rate	$ 3.6073		$ 3.6073	
Supplier Refund Adjustment (RA)	(0.0104)		(0.0104)	
Actual Adjustment (AA)	(0.0997)		(0.0997)	
Balance Adjustment (BA)	0.2734		0.2734	
Gas Cost Recovery Rate (GCR)	**$ 3.7706**		**$ 3.7706**	
Canada Mountain Costs in May GCR		$ 2,395,489		
Test Period Retail Sales (see below)		4,407,309		
Canada Mountain Recovery / Mcf			0.5435	
	$ 3.7706		**$ 3.2271**	**$ (0.5435)**

Test Period GCR Revenues	Mcf	*Revenue @ $3.7706*	*Revenue @ $3.2271*	Difference
General Service				
Residential	2,581,793	9,734,907	8,331,703	(1,403,204)
Commercial - Small	682,889	2,574,901	2,203,750	(371,150)
Lg. Commercial & Industrial				
Retail Sales	1,097,390	4,137,820	3,541,388	(596,432)
Transportation	745,594			
Total Lg. Com. & Ind.	1,842,984			
Total General Service	5,107,666			
Interruptible Service				
Retail Sales	45,238	170,573	145,986	(24,587)
Transportation	1,391,510			
Total Interruptible Service	1,436,748			
Total GCR Revenues		$ 16,618,200	$ 14,222,828	(2,395,373)
Rate Case Test Period Sales	*4,407,309*		*$ (2,395,373)*	*$ (0.5435)*

Schedule 24
Supporting Worksheet

DELTA NATURAL GAS COMPANY INC
Cost of Service – Revenue Requirement
Test Period Ended 12/31/98

Line No			
1	Cost of Gas	Schedule 3	$16,618,201
2	Operations & Maintenance Expense	Schedule 4	$ 8,899,157
3	Depreciation Expense	Schedule 5	$ 4,013,852
4	Taxes Other Than Income Taxes	Schedule 5	$ 1,232,785
5	Return	Schedule 7	$ 8,340,065
6	Income Tax	Schedule 8	$ 3,045,166
7	Total Cost of Service		$42,149,226
8	Revenues at Present Rates	Schedule 2	$37,293,317
9	Revenue Deficiency		$ 4,855,910

DELTA NATURAL GAS COMPANY INC
O & M Adjustments
Test Year Ended 12/31/98

Line No.				
1	Adjustments to Payroll			116,199
2	Accounts Disallowed in Case No. 97-066			(142,711)
3	Remove Canada Mtn			(120,120)
5	Rate Case Expense		145,000	29,000
6	Customer Deposits	6%	594,863	35,692
7	Medical Adj-Stop Loss			77,561
8	New Customers Added			54,498
9	Total O & M Adjustments			50,119
10	O & M Per Books			8,727,918
11	O & M Adjusted			8,778,037
12	Add Canada Mtn			120,120
13	O & M Adjusted			8,898,157

Delta Natural Gas Company, Inc.

Revised Summary of Proposed Increase by Rate Class

In Response to PSC Data Request dated Sep. 14, 1999 - Item 5

	Actual Billed Revenue	Elimination of GCR Revenues	Current Rates for Full Year and Rate Switching	Net Before Temperature and Year-End Adjustments	Temperature Normalization Adjustment	Year-End Customers	Adjusted Billings @ Base Rates	GCR @ Current Charges	Adjusted Billings @ Current Rates	Proposed Increase in Base Rate Revenue	Proposed Increase in Overall Revenue	Overall Percentage Increase
REVENUE										(1.)	(1.)	
General Service								$ 3.7706				
Residential	18,296,074	(9,431,520)	42,919	8,907,472	1,019,080	183,444	10,109,997	9,734,907	19,844,904	3,343,187	1,939,983	9.78%
Commercial - Small	4,845,419	(2,446,952)	11,370	2,409,837	253,286	101,346	2,764,469	2,574,901	5,339,370	782,602	411,452	7.71%
Lg. Commercial & Industrial												
Retail Sales	6,944,686	(4,208,243)	17,227	2,753,670	337,794	2,640	3,094,104	4,137,820	7,231,924			
Transportation	1,469,977		(95,851)	1,374,126	74,550		1,448,676		1,448,676			
Total Lg. Com. & Ind.	8,414,662	(4,208,243)	(78,623)	4,127,796	412,344	2,640	4,542,780	4,137,820	8,680,600	835,269	238,837	2.75%
Total General Service	31,556,155	(16,086,716)	(24,334)	15,445,105	1,684,711	287,430	17,417,246	16,447,628	33,864,874	4,961,058	2,590,273	7.65%
Interruptible Service												
Retail Sales	254,214	(173,321)		80,893	8,747		89,640	170,573	260,213			
Transportation	1,931,707			1,931,707			1,931,707		1,931,707			
Total Interruptible Service	2,185,922	(173,321)		2,012,600	8,747		2,021,347	170,573	2,191,920	(105,353)	(129,939)	-5.93%
Special Contracts	511,666		104,167	615,833		16,689	632,522		632,522			
Off-System Transportation	451,990			451,990			451,990		451,990			
Total Sales and Transportation	34,705,733	(16,260,037)	79,833	18,525,529	1,693,458	304,119	20,523,106	16,618,200	37,141,307	4,855,706	2,460,333	6.62%
Miscellaneous Service Revenues	152,009			152,009			152,009		152,009			
Total Gas Operating Revenue	34,857,742	(16,260,037)	79,833	18,677,538	1,693,458	304,119	20,675,115	16,618,200	37,293,316	4,855,706	2,460,333	6.60%
MCF												
General Service												
Residential	2,142,320			2,142,320	374,497	64,976	2,581,793					
Commercial - Small	553,669			553,669	93,394	35,826	682,889					
Lg. Commercial & Industrial												
Retail Sales	966,462			966,462	130,046	882	1,097,390					
Transportation	756,019		(49,423)	706,596	38,998		745,594					
Total Lg. Com. & Ind.	1,722,481		(49,423)	1,673,058	169,044	882	1,842,984					
Total General Service	4,418,470		(49,423)	4,369,047	636,935	101,684	5,107,666					
Interruptible Service												
Retail Sales	39,805			39,805	5,433		45,238					
Transportation	1,391,510			1,391,510			1,391,510					
Total Interruptible Service	1,431,315			1,431,315	5,433		1,436,748					
Special Contracts	1,755,567		49,423	1,804,990		12,286	1,817,276					
Off-System Transportation	1,404,111			1,404,111			1,404,111					
Total Sales and Transportation	9,009,463		-	9,009,463	642,367	113,970	9,765,801					

1. See revised Schedule 24 filed pursuant to this request and supporting worksheets

DELTA NATURAL GAS COMPANY INC
Depreciation Adjustment
Test Year Ended 12/31/98

Line No		
1	Depreciated Expense	3,550,142
2	Per Books	3,570,354
3	Adjustment	(20,212)
4	Add Canada Mtn	463,710
5	Adjustment	443,498
6	Per Books	3,570,354
		4,013,852

DELTA NATURAL GAS COMPANY
Payroll Tax Adjustment
Test Year Ended 12/31/98

Payroll Tax and Property Tax Adjustment

Line No		
1	Direct Total Payroll for 12 Months Ended 12/31/98	6,251,888
2	Payroll Taxes (A/C # 1.408.03)	480,841
3	Payroll Taxes Percent of Payroll	7.69%
4	Payroll Increase	116,119
5	Payroll Tax Increase	8,937
6	Remove Canada Mt. Property Taxes	(47,147)
7	Total Adjustment to Taxes Other Than Income Taxes	(38,210)
8	Taxes Other than Income Taxes @ 12/31/98	1,223,848
9	Taxes Other than Income Taxes Adjusted	1,185,638
10	Add Canada Mtn	47,147
11	Taxes Other than Income Taxes Adjusted	1,232,785

DELTA NATURAL GAS COMPANY INC
Rates Base and Return
Test Year Ended 12/31/98

Rate Base: Line No			
1	Property		129,288,796
2	Less Reserve for Depreciation		(35,973,200)
3	Net Plant		93,315,596
4	Working Capital		1,112,395
5	Prepayments		106,884
6	Materials and Supplies, at Cost		451,812
7	Gas in Storage, at Cost		265,579
8	Accumulated Provision for Deferred Income Taxes		(8,436,725)
9	Unamortized Debt	100%	3,650,173
10	Advances for Construction		(220,060)
11	Depreciation Adjustment		(443,498)
12	Total Rate Base		89,802,156
14	Return @ 9.2872%		8,340,065

DELTA NATURAL GAS COMPANY INC
Income Tax Adjustment
Test Year Ended 12/31/98

Line No			
1	INCOME TAX ADJUSTMENT		
2	Net Income Books		1,705,196
3	Income Tax Books		973,775
4	Taxable Income/Books		2,678,971
5	LESS ADJUSTMENTS		
6	Rev & Gas Costs		(14,182,627)
7	Oper Exp		(14,367,777)
8	Adjusted Income Before Taxes		2,864,121
9	Adjusted Income Tax at	39.445%	1,129,753
10	Income Tax Books		973,775
11	As Adjusted		155,978
12	Adjusted Income Taxes @ 12/31/98		1,129,753
13	Income Taxes on Revenue Deficiency		1,915,414
14	Total Income Taxes		3,045,166

DELTA NATURAL GAS COMPANY INC
Interest Costs Adjustment
Test Year Ended 12/31/98

Interest Costs Adjustment

Line No		**AMOUNT**	**RATE**	**INTEREST**
1	Long Term Debt	$37,161,228	7.4786%	$ 2,779,121
2	Short Term Debt	$ 6,190,353	5.4100%	$ 334,898
3				$ 3,114,019
4				
5	Interest per Books			$ 4,509,474
6	Adjustment Required			$ (1,395,455)
7	Canada Mtn Interest			$ 551,181
8	Adjustment			$ (844,274)

INCOME STATEMENT:

	Per Books	---Adjustments to test period--- Revenues	Expenses	Income Taxes	Adjusted Test Period	Increase Required	Adjusted For Increase
Net Operating Revenues	34,857,742	(14,182,627)			20,675,115	4,855,910	25,531,025
Operating Expenses							
Gas Purchased	14,147,177	0	(14,147,177)		0		0
Operations & Maintenance	8,727,918	0	171,239		8,899,157		8,899,157
Depreciation	3,570,354		443,498		4,013,852		4,013,852
Other Taxes	1,223,848	0	8,937		1,232,785		1,232,785
Income Taxes	973,775			155,978	1,129,753	1,915,414	3,045,166
Total	28,643,072	0	(13,523,503)	155,978	15,275,547	1,915,414	17,190,960
Operating Income	6,214,670	(14,182,627)	(13,523,503)	155,978	5,399,568	2,940,497	8,340,065
	0	0			0		0
Interest on Debt	4,509,474		(844,274)		3,665,200		3,665,200
Amort of Debt Expense	0				0		0
Total Debt Expense	4,509,474	0	(844,274)		3,665,200		3,665,200
Net Income	1,705,196	(14,182,627)	(14,367,777)	155,978	1,734,368	2,940,497	4,674,865

ASSETS	Per Books 12/31/98	Subs	Proposed Adjustment	Proposed
UTILITY PLANT	125,206,004	0	1,587,945	126,793,949
Less-Accumulated provision				0
for depreciation	-33,478,352	0	-20,212	-33,498,564
Net utility plant	91,727,652	0	1,567,733	93,295,385
CURRENT ASSETS				
Cash	422,379		674,876	1,097,255
Accounts receivable - net	1,781,108		-1,781,108	0
Deferred gas cost	1,354,892		-1,354,892	0
Gas in storage	3,364,903		-3,099,324	265,579
Materials and supplies	451,812			451,812
Prepayments	106,884			106,884
Total current assets	7,481,978		-5,560,448	1,921,530
OTHER ASSETS				
Cash surrender value of				
officers' life insurance	347,789		-347,789	0
Unamortized debt	3,650,173		-541,248	3,108,925
Invest in subs	1,466,060	-1,280,279	-185,781	0
Other	1,049,138		-1,049,138	0
Total other assets	6,513,160	-1,280,279	-2,123,956	3,108,925
Total assets	105,722,790	-1,280,279	-6,116,671	98,325,840
LIABILITIES AND SHAREHOLDERS' EQUITY				
CAPITALIZATION				
Common shareholders' equity	28,351,812	-1,280,279	10,509,355	37,580,888
Long-term debt	54,207,845	0	-9,008,680	45,199,165
Total capitalization	82,559,657	-1,280,279	1,500,675	82,780,053
CURRENT LIABILITIES				
Notes payable	9,030,000	0	-2,140,998	6,889,002
Current portion of long-ter	0			0
Accounts payable	1,749,573		-1,749,573	0
Accrued taxes	-441,509		441,509	0
Refunds due customers	72,839		-72,839	0
Customers' deposits	594,864		-594,864	0
Accrued interest on debt	1,220,198		-1,220,198	0
	0		0	0
Other current and accrued				
liabilities	881,858		-881,858	0
Total current liabiliti	13,107,823	0	-6,218,821	6,889,002
DEFERRED CREDITS AND OTHER				
Deferred income taxes	8,436,725		0	8,436,725
Investment tax credits	602,550		-602,550	0
Regulatory liability	795,975		-795,975	0
Advances for construction a	220,060		0	220,060
Total deferred credits	10,055,310		-1,398,525	8,656,785
	105,722,790	-1,280,279	-6,116,671	98,325,840

Notes

6

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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?

RESPONSE:

a. Delta completed the construction of its Canada Mountain facilities in October 1997.

Sponsoring Witness:

Glenn R. Jennings

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

7. State the percentage of Canada Mountain's storage capacity that Delta is currently using.

RESPONSE:

Since the Canada Mountain field has been developed and utilized as a storage field, Delta has used 100% of the available capacity to help meet the daily and seasonal needs of its firm customer requirements. Delta has continued to ratchet up the working gas inventory levels as the field has been tested, developed and monitored. As the field develops and Delta's customers' needs require, the working gas levels will be increased.

Sponsoring Witness:

Glenn R. Jennings

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

8. Provide all contracts and lease agreements between Delta and Deltran that involve the Canada Mountain storage facilities.

RESPONSE:

Attached are copies of the Lease Agreement and the Gas Storage Agreement by and between Delta and Deltran.

Sponsoring Witness:

Glenn R. Jennings

LEASE AGREEMENT

THIS LEASE AGREEMENT ("Agreement") made and entered into this 1st day of January, 1996, by and between Delta Natural Gas Company, Inc. ("Delta"), a Kentucky corporation, whose address is 3617 Lexington Road, Winchester, Kentucky 40391, and Deltran, Inc. ("Deltran"), a Kentucky corporation, whose address is 3617 Lexington Road, Winchester, Kentucky 40391.

WITNESSETH:

WHEREAS, Delta is the owner of a natural gas storage field located on Canada Mountain in Bell County, Kentucky and related pipeline, measurement and compression facilities located in Bell and Knox Counties, Kentucky, (collectively referred to herein as the "Storage Field");

WHEREAS, Delta owns and operates a natural gas distribution system in the vicinity of the Storage Field;

WHEREAS, Delta desires to lease the Storage Field to Deltran, and Deltran desires to lease the Storage Field from Delta and to operate the Storage Field;

NOW, THEREFORE, in consideration of the mutual covenants and agreements hereinafter set forth, the parties hereto agree as follows:

1. Grant and Term. In consideration of the payment of the monthly lease charges as set forth on Exhibit "A" attached hereto, as same may be modified from time to time, Delta does hereby lease to Deltran the Storage Field effective on the date first above written and continuing for twelve (12) months thereafter. The term shall continue year-to-year thereafter until terminated by either party providing not less than six (6) months written notice to the other party.

2. Payment. On or before the tenth (10th) day of each calendar month hereof, Delta shall render to Deltran a statement setting forth the amounts due Delta in accordance with Exhibit "A" hereto. On or before the twenty-fifth (25th) day of each month, Deltran shall render payment in the amount due Delta.

3. Storage Field Capacity. During the term of this Agreement, Deltran hereby dedicates the entire working gas capacity of the Storage Field to Delta.

4. Title and Ownership. Delta and Deltran agree that this Agreement does not convey title to or any incident of ownership of the Storage Field. The parties expressly intend this Agreement to be a true lease and not a sale or security agreement.

5. Compliance with Laws. Deltran shall conduct all its natural gas storage operations in a good and workmanlike manner and in all material respects in conformity with natural gas industry standards. Deltran shall comply in all material respects with all applicable local, state, and federal laws, rules, orders, ordinances, and regulations in its operations and maintenance of the Storage Field.

6. Governmental Regulation. This Agreement and all provisions herein will be subject to all applicable and valid statutes, rules, orders and regulations of any Federal, State, or local governmental authority having jurisdiction over the parties, their facilities, this Agreement or any provisions hereof. This Agreement shall not be effective in whole or in part until and unless all necessary regulatory approvals or authorizations shall have been obtained to the satisfaction of each of the parties hereto. In the event any such approval or authorization is withdrawn or expires (and any renewal is refused by the appropriate regulatory authority), this Agreement may be canceled at the option of either party hereto upon ten (10) days written notice.

7. Operation, Maintenance and Repairs. Deltran shall operate and maintain the Storage Field and appurtenant pipelines, compressors and fixtures, including any modifications or additions, in good operating and mechanical condition, normal wear and tear from authorized use excepted.

8. Notices. All notices, requests, statements and other communications hereunder shall be in writing and shall be delivered as follows:

To Delta: Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
Attention: President

To Deltran: Deltran, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
Attention: President

or at such other address as the parties may designate in writing.

9. Waiver. A waiver by either party of any one or more defaults by the other party in the performance of any provision of this Agreement shall not operate as a waiver of any other default.

10. Severability. Except as otherwise may be provided herein, any provision of this Agreement declared or rendered unlawful by statute, court of law or regulatory agency with jurisdiction over the parties or either of them, shall not otherwise affect the other obligations of the parties under this Agreement.

11. Entire Agreement. This Agreement contains the entire agreement between the parties and there are no promises, agreements, warranties, obligations, assurances or conditions other than those contained herein.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date first hereinabove written.

DELTA NATURAL GAS COMPANY, INC.

BY: ______________________

ITS: MGR. - GAS Supply

DELTRAN, INC.

BY: Glenn R. Jennings

ITS: President

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 4,900.00
EFFECTIVE DATE:	JANUARY 1, 1996

FIRST REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 25,047.00
EFFECTIVE DATE:	MAY 1, 1996

REVISION DATE: MARCH 28, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR - GAS Supply	ITS: President

SECOND REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 52,477.00
EFFECTIVE DATE:	AUGUST 1, 1996

REVISION DATE: JUNE 24, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR. - GAS SUPPLY	ITS: President & CEO

THIRD REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 70,088
EFFECTIVE DATE:	NOVEMBER 1, 1996

REVISION DATE: SEPTEMBER 25, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President & CEO

FOURTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 96,428.00
EFFECTIVE DATE:	FEBRUARY 1, 1997

REVISION DATE: DECEMBER 23, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President & CEO

FIFTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE: $ 110,278.00

EFFECTIVE DATE: MAY 1, 1997

REVISION DATE: MARCH 26, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: Gary S. Biering	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President + CEO

SIXTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 129,737.00
EFFECTIVE DATE:	AUGUST 1, 1997

REVISION DATE: JUNE 19, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: Mgr - Gas Supply	ITS: President & CEO

SEVENTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 147,404.00
EFFECTIVE DATE:	NOVEMBER 1, 1997

REVISION DATE: SEPTEMBER 19, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President + CEO

EIGHTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 200,151.00
EFFECTIVE DATE:	FEBRUARY 1, 1998

REVISION DATE: DECEMBER 26, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

NINTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 178,951.00
EFFECTIVE DATE:	MAY 1, 1998

REVISION DATE: MARCH 25, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: [signature]
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

TENTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 175,924.00
EFFECTIVE DATE:	AUGUST 1, 1998

REVISION DATE: JUNE 24, 1998

DELTA NATURAL GAS COMPANY, INC.

BY: Glenn S. Billings

ITS: MANAGER - GAS SUPPLY

DELTRAN, INC.

BY: Glenn R. Jennings

ITS: PRESIDENT & C.E.O.

ELEVENTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 193,511.00
EFFECTIVE DATE:	NOVEMBER 1, 1998

REVISION DATE: September 28, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: Amy S. Bieling	BY: Glenn R. Jennings
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

TWELFTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 209,651.00
EFFECTIVE DATE:	FEBRUARY 1, 1999

REVISION DATE: December 17, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: ______________________	BY: ______________________
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

THIRTEENTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 199,624.00
EFFECTIVE DATE:	MAY 1, 1999

REVISION DATE: March 25, 1999

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY:
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

FOURTEENTH REVISED

EXHIBIT "A"

TO LEASE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY LEASE CHARGE:	$ 197,526.00
EFFECTIVE DATE:	AUGUST 1, 1999

REVISION DATE: June 28, 1999

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: [signature]
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

GAS STORAGE AGREEMENT

THIS AGREEMENT is made and entered into this 1st day of January, 1996, by and between Deltran, Inc., a Kentucky corporation, hereinafter referred to as "Deltran", and Delta Natural Gas Company, Inc., a Kentucky corporation, hereinafter referred to as "Delta".

WITNESSETH:

WHEREAS, Deltran is the operator of a natural gas storage field located on Canada Mountain in Bell County, Kentucky and related pipeline, measurement and compression facilities located in Bell and Knox Counties, Kentucky under the terms of the Lease Agreement dated January 1, 1996 by and between the parties hereto;

WHEREAS, Delta owns and operates a natural gas distribution system in the vicinity of Deltran's storage operation;

WHEREAS, Deltran desires to dedicate the capacity of its storage field to Delta and the parties hereto desire to enter into an agreement for the receipt, storage and redelivery of natural gas by Deltran;

NOW THEREFORE, in consideration of the mutual agreements and covenants herein set forth, Deltran agrees to accept, hold in its possession, and redeliver the quantities of gas for Delta as herein set forth, and Delta agrees to pay Deltran for the storage services in accordance with the further provisions of this Agreement.

ARTICLE I - SCOPE OF THE AGREEMENT

Upon the effective date and in accordance with the terms of this Agreement, Deltran shall receive at the Service Point(s) for Delta's account up to the daily and cumulative quantities of gas as specified by Delta. Upon demand by Delta, Deltran shall withdraw from Delta's storage account and redeliver to Delta at the Service Point(s) up to the daily quantity of gas as specified by Delta. Deltran hereby dedicates the entire working gas capacity of the storage field to Delta.

ARTICLE II - SERVICE POINT

The point(s) at which the gas is tendered for delivery to or from Deltran under this Agreement shall be at the service point(s) at the interconnection of the facilities of Deltran and Delta at or near Flat Lick, Kentucky and at the interconnection of the facilities of Deltran and Delta at or near Yellow Hill, Bell County, Kentucky.

ARTICLE III - PRICE

Commencing with the execution of this Agreement, Delta agrees to pay Deltran a monthly Reservation Charge for the storage service for Delta as set forth on Exhibit "A" attached hereto, as same may be modified from time to time.

ARTICLE IV - QUALITY

All gas delivered by Delta to Deltran and redelivered by Deltran to Delta hereunder shall be merchantable and shall conform to Delta's gas quality specifications.

ARTICLE V - MEASUREMENT

(1) All gas delivered and redelivered at the Service Point(s) shall be measured by an orifice, turbine or displacement type meter or other approved measuring device of equal accuracy to be owned and installed by Deltran and to be operated and maintained by Delta. Delta shall read the meter, furnish the charts, place and remove any and all recording gauge charts, calculate the deliveries and redeliveries, and perform any other service necessary in connection with the measurement of said gas.

(2) All unaccounted for gas and volumes used as compressor fuel in the storage operations shall be provided by Delta.

ARTICLE VI - TERM

Subject to the provisions of Article VIII, this Agreement shall become effective on the date first above written and shall continue for twelve (12) months thereafter. The term shall continue year-to-year thereafter until or unless canceled by either party providing the other party not less than six (6) months written notice. Upon termination of the Agreement, Delta shall have not less than ninety (90) days in which to withdraw volumes remaining in its storage account.

ARTICLE VII - BILLING AND PAYMENT

Deltran will render to Delta, on or before the tenth (10th) day of each calendar month a statement setting forth the amounts due Deltran in accordance with Exhibit "A" hereto, as same may be modified from time to time. On or before the twenty-fifth (25th) day of each month, Delta shall render payment in the amount due Deltran.

ARTICLE VIII - GOVERNMENTAL REGULATION

This Agreement and all provisions herein will be subject to all applicable and valid statutes, rules, order and regulations of any Federal, State, or local governmental authority having jurisdiction over the parties, their facilities, this Agreement or any provisions hereof. This Agreement shall not be effective in whole or in part until and unless all necessary regulatory approvals or authorizations shall have been obtained to the satisfaction of each of the parties hereto. In the event any such approval or authorization is withdrawn or expires (and any renewal is refused by the appropriate regulatory authority), this Agreement may be canceled at the option of either party hereto upon ten (10) days written notice.

ARTICLE IX - WARRANTY

Delta warrants to Deltran that it will have good title to or be in lawful possession of all gas delivered to Deltran hereunder; that such gas will be free and clear of all liens, encumbrances and claims whatsoever; that it will at the time of delivery have the right to deliver or cause to be delivered the gas hereunder; and that it will indemnify Deltran and save it harmless from suits, actions, debts, accounts, damages, costs, losses and expenses arising from or out of adverse claims of any and all persons to said gas or to royalties, taxes, license fees or charges thereon.

ARTICLE X - RESPONSIBILITY

As between the parties hereto, it is agreed that from the time gas is delivered hereunder to Deltran at the Service Points until the redelivery of the gas to Delta at the Service Points, Deltran will assume all responsibility for such gas, will indemnify and hold Delta harmless against any injuries or damages caused thereby and will have the unqualified right to commingle such gas with other gas in its storage operations and to handle and treat such gas as its own. Prior to such delivery and subsequent to such redelivery, Delta will assume all responsibility for such gas and will indemnify and hold

Deltran harmless for any injuries or damages caused thereby.

ARTICLE XI - FORCE MAJEURE

In case either party to this Agreement fails to perform any obligations hereunder assumed by it and such failure is due to acts of God or a public enemy, strikes, riots, injunctions, or other interference through legal proceedings, breakage or accident to machinery or lines of pipe, washouts, earthquakes, storms, freezing of lines or wells, blowouts, the failure of wells in whole or part, or the compliance with any statute, either State or Federal, or with any order of the Federal Government or any branch thereof, or of the Governments of the State wherein subject premises are situated, or to any causes not due to the fault of such party, or is caused by the necessity for making repairs or alterations in machinery or lines of pipe, such failure shall not be deemed to be a violation by such party of its obligations hereunder, but such party shall use due diligence to again put itself in position to carry out all of the obligations which by the terms hereof it has assumed. It is expressly understood and agreed, however, that this Article XI shall not apply to the obligation of Delta to pay for the storage service hereunder.

ARTICLE XII - NOTICES

All notices, requests, statements and other communications hereunder shall be in writing and shall be delivered as follows:

To Deltran:

Deltran, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
Attention: President

To Delta:

Delta Natural Gas Company, Inc.
3617 Lexington Road
Winchester, Kentucky 40391
Attention: President

or at such other address at the parties may designate in writing.

ARTICLE XIII - WAIVER

A waiver by either party of any one or more defaults by the other in the performance of any provision of this Agreement, shall not operate as a waiver of any other default.

ARTICLE XIV - SEVERABILITY

Except as otherwise provided herein, any provision of this Agreement declared or rendered unlawful by a statute, court of law or regulatory agency with jurisdiction over the parties or either of them, shall not otherwise affect the other obligations of the parties under this Agreement.

ARTICLE XV - ENTIRE AGREEMENT

This Agreement supersedes and replaces that Gas Storage Agreement dated October 31, 1995 previously executed between the parties hereto and is the entire agreement between the parties. There are no promises, agreements, warranties, obligations, assurances or conditions other than those contained herein.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date first hereinabove written.

DELTRAN, INC.

BY: Glenn R. Jennings

ITS: President

DELTA NATURAL GAS COMPANY, INC.

BY: [illegible] S. [illegible]

ITS: MGR. - GAS Supply

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BETWEEN DELTRAN, INC. AND DELTA NATURAL GAS COMPANY, INC.

Monthly Reservation Charge:	$4,900.00
Effective Date:	JANUARY 1, 1996

FIRST REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 25,047.00
EFFECTIVE DATE:	MAY 1, 1996

REVISION DATE: MARCH 28, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R Jennings
ITS: MGR - GAS Supply	ITS: President

SECOND REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 52,477.00
EFFECTIVE DATE:	AUGUST 1, 1996

REVISION DATE: JUNE 24, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President & CEO

THIRD REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 70,088
EFFECTIVE DATE:	NOVEMBER 1, 1996

REVISION DATE: SEPTEMBER 25, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President & CEO

FOURTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 96,428.00

EFFECTIVE DATE: FEBRUARY 1, 1997

REVISION DATE: DECEMBER 23, 1996

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: Larry S. Billings	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President + CEO

FIFTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 110,278.00
EFFECTIVE DATE:	MAY 1, 1997

REVISION DATE: MARCH 26, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: Gary S. Billings	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President & CEO

SIXTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 129,737.00

EFFECTIVE DATE: AUGUST 1, 1997

REVISION DATE: JUNE 19, 1997

DELTA NATURAL GAS COMPANY, INC.

BY: Gary S. Biering

ITS: MGR. - GAS Supply

DELTRAN, INC.

BY: Glenn R. Jennings

ITS: President & CEO

SEVENTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 147,404.00
EFFECTIVE DATE:	NOVEMBER 1, 1997

REVISION DATE: SEPTEMBER 19, 1997

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: Gary S. Billings	BY: Glenn R. Jennings
ITS: MGR. - GAS Supply	ITS: President + CEO

EIGHTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 200,151.00

EFFECTIVE DATE: FEBRUARY 1, 1998

REVISION DATE: DECEMBER 26, 1997

DELTA NATURAL GAS COMPANY, INC.

BY:

ITS: MANAGER - GAS SUPPLY

DELTRAN, INC.

BY:

ITS: PRESIDENT & C.E.O.

NINTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 178,951.00

EFFECTIVE DATE: MAY 1, 1998

REVISION DATE: MARCH 25, 1998

DELTA NATURAL GAS COMPANY, INC.

BY: [signature]

ITS: MANAGER - GAS SUPPLY

DELTRAN, INC.

BY: [signature]

ITS: PRESIDENT & C.E.O.

TENTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 175,924.00

EFFECTIVE DATE: AUGUST 1, 1998

REVISION DATE: JUNE 24, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY: [signature]	BY: [signature]
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

ELEVENTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE:	$ 193,511.00
EFFECTIVE DATE:	NOVEMBER 1, 1998

REVISION DATE: SEPTEMBER 28, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY:
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

TWELFTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 209,651.00

EFFECTIVE DATE: FEBRUARY 1, 1999

REVISION DATE: December 17, 1998

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY:
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

THIRTEENTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 199,624.00

EFFECTIVE DATE: MAY 1, 1999

REVISION DATE: March 25, 1999

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY:
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

FOURTEENTH REVISED

EXHIBIT "A"

TO GAS STORAGE AGREEMENT DATED JANUARY 1, 1996

BY AND BETWEEN DELTA NATURAL GAS COMPANY, INC. AND DELTRAN, INC.

MONTHLY RESERVATION CHARGE: $ 197,526.00

EFFECTIVE DATE: AUGUST 1, 1999

REVISION DATE: June 28, 1999

DELTA NATURAL GAS COMPANY, INC.	DELTRAN, INC.
BY:	BY: Glenn R. Jennings
ITS: MANAGER - GAS SUPPLY	ITS: PRESIDENT & C.E.O.

Notes

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.

   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.

RESPONSE:

a. See Schedule 1 Attached

b. (1) This amount is the balance of Account 1.164.03 Canada Mountain Storage Gas as of 12/31/98. See schedule 3 in response to Item 9. c. of this request. Amount can be found in Non-Rate Base Assets column, Line 9.

   (2) See Schedule 2 Attached

   (3)

Account	Account Description	Amount
1.141.00	Notes Receivable Officer	134,000
1.141.01	Notes Recvbl Due in 1Yr Offset	(24,000)
1.165.02	Prepaid Pension Cost	717,283
1.186.01	Unamortized Mgnt Audit Expense	187,858
1.186.02	Unamortized Rate Case Exp #97-066	129,048
1.186.05	Amortized Rate Case Exp #97-066	(27,253)
1.186.06	Amortized Management Audit Expense	(67,798)
		1,049,138

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

c. See attached Schedule 3 which lays out PSC Case Number 99-176 data request dated 8/11/99 for Item 23 and data request dated 7/2/99 for Item 38 in a manner which more clearly shows the source of the individual adjustments, and also reconciles capital structure and rate base.

As Schedule 3 details, the following summarizes the reconciling items:

Non-Rate Base Liabilities	(5,476,348)
Non-Rate Base Assets	8,359,280
Tranex	(1,587,945)
Working Capital	(674,876)
Depr Normalization	20,212
	640,323

WITNESS RESPONSIBLE: John Hall

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Line Number	ITEM 9 a. RESPONSE	CASE NO 98-055 BALANCE AT 10/31/97	CASE NO 99-176 BALANCE AT 12/31/98
1	Canada Mtn Plant	5,323,084	10,391,422
2	Canada Mtn CWIP	4,706,060	213,713
3	Canada Mtn Cushion Gas	3,718,035	3,718,035
4	Canada Mtn Storage Gas	2,512,620	
5	Unamortized Debt Issuance	326,203	
6	Note Payable to Ferrin	(1,800,000)	
7	Accumulated Depreciation	(362,238)	
8		14,423,764	14,323,170

Refer to Schedule 3 in Response to Item 9. c. of this request.
This amount, at 12/31/98 (14,323,170) is reflected in Canada Mountain Plant Column, Line 1.

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

RESPONSE TO 9 b. (2):

Line Number	Account	Description	Amount
1	1.123.02	Investment in Delta Resources	24,866
2	1.123.03	Investment in Delgasco	4,073
3	1.123.04	Investment in Deltran	1,000
4	1.123.05	Investment in Enpro	216,236
5	1.123.06	Investment in Tranex	885,475
6	1.146.02	Receivable Delta Resources	(272,528)
7	1.146.03	Receivable From Delgasco	(1,128,668)
8	1.146.04	Receivable from Deltran	(1,000)
9	1.146.05	Receivable from Enpro	1,231,901
10	1.146.06	Receivable from Tranex	504,706
11		Investment in Subs	1,466,061
12			
13		Less:	
14		Enpro Plant	2,097,722
15		Enpro Accum Depr	(817,443)
16		Enpro Net Plant	1,280,279
17			
18		Adjustment	185,782

SCHEDULE 3

Line Number		Per Books 12/31/98	Non-Rate Base Liabilities	Non-Rate Base Assets	Subsidiaries	Canada Mountain Plant	Tranex	Working Capital	Depr. Norm	TOTAL
	ASSETS									
1	UTILITY PLANT	125,206,004				(14,323,170)	1,587,945			112,470,779
2	Less Accum Depr	(33,478,352)				742,254			(20,212)	(32,756,310)
3	Net Utility Plant	91,727,652	-	-		(13,580,916)	1,587,945	-	(20,212)	79,714,469
4										
5	CURRENT ASSETS									
6	Cash	422,379						674,876		1,097,255
7	Accts Receivable - Net	1,781,108		(1,781,108)						-
8	Deferred Gas Cost	1,354,892		(1,354,892)						-
9	Gas in Storage	3,364,903		(3,099,324)						265,579
10	Materials and Supplies	451,812								451,812
11	Prepayments	106,884								106,884
12	Total Current Assets	7,481,978	-	(6,235,324)		-	-	674,876	-	1,921,530
13										
14	OTHER ASSETS									
15	Cash Surrender Value of Offcrs' Life Ins	347,789		(347,789)						-
16	Unamortized Debt	3,650,173		(541,248)						3,108,925
17	Invest in Subs	1,466,060		(185,781)	(1,280,279)					-
18	Other	1,049,138		(1,049,138)						-
19	Total Other Assets	6,513,160	-	(2,123,956)	(1,280,279)	-	-	-	-	3,108,925
20	**TOTAL ASSETS**	105,722,790	-	(8,359,280)	(1,280,279)	(13,580,916)	1,587,945	674,876	(20,212)	84,744,924
21										
22										
23	**LIABILITIES AND SHAREHOLDERS' EQUITY**									
24	CAPITALIZATION									
25	Common shareholders' equity	(28,351,812)								
26	Long-term debt	(54,207,845)								
27										
28	CURRENT LIABILITIES									
29	Notes Payable	(9,030,000)								
30	**TOTAL CAPITAL STRUCTURE**	(91,589,657)	-	-	1,280,279	13,580,916	-	-	-	(76,728,462)
31										
32	Accounts Payable	(1,749,573)	1,749,573							-
33	Accrued Taxes	441,509	(441,509)							-
34	Refunds due customers	(72,839)	72,839							-
35	Customers' Deposits	(594,864)	594,864							-
36	Accrued interest on debt	(1,220,198)	1,220,198							-
37	Other current and accrued liabilities	(881,858)	881,858							-
38	Total Current Liabilities	(4,077,823)	4,077,823	-		-	-	-	-	-
39										-
40	DEFERRED CREDITS AND OTHER									-
41	Deferred income taxes	(8,436,725)								(8,436,725)
42	Investment tax credits	(602,550)	602,550							-
43	Regulatory liability	(795,975)	795,975							-
44	Advances for Construction	(220,060)								(220,060)
45	Total Deferred Credits	(10,055,310)	1,398,525	-		-	-	-	-	(8,656,785)
46	**TOTAL LIABILITIES**	(105,722,790)	5,476,348	-	1,280,279	13,580,916	-	-	-	(85,385,247)
47										
48	**RATE BASE**	91,589,657	5,476,348	(8,359,280)	(1,280,279)	(13,580,916)	1,587,945	674,876	(20,212)	76,088,139
49										
50	**RATE BASE VS. CAPITAL STRUCTURE DIFF**	-	5,476,348	(8,359,280)	-	-	1,587,945	674,876	(20,212)	(640,323)

Notes

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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").

RESPONSE:

Delta acquired the North Middletown natural gas distribution system from the City of North Middletown. The acquisition occurred effective November 18, 1996. A copy of the journal entry to record the purchase is included below:

Account Number	Account Description	General Ledger Debit	Credit
101	Gas Plant in Service	230,000.00	
131	Cash		230,000.00

There was no acquisition adjustment. The assets were purchased and recorded at cost on the date of purchase.

SPONSORING WITNESS: John Brown

Notes

11

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

PSC Data Request Dated 9/14/99

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.
   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 price 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.

Response:

There was no acquisition adjustment. The assets were purchased and recorded at cost on the date of purchase. See Response 10 for Journal Entry.

Witness:

John Brown

Notes

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

PSC Data Request Dated 9/14/99

12. Refer to Delta's Response to the Commission's Order of August 11, 1999, Item 25(a). Explian 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

RESPONSE:

a. The prepayments included in rate base for the test year do not relate in any way to the subsidiaries; therefore, prepayments should not be allocated to the subsidiaries. As answered in The Attorney General's August 11, 1999 Request For Information, Item 15, Delta's insurance policies do cover the compressor stations, operator's extra expense and blanket surety for gas wells at Canada Mountain, but these items are not detailed in the policies. Insurance is not a cost that has been recovered through the Canada Mountain Gas Cost Recovery Mechanism, so the costs are not being duplicated in recovery.

b. Delta does not maintain inventory for any of the subsidiaries; therefore, material and supplies should not be allocated to the subsidiaries. This is consistent with the answer given in AG 8/11/99 item 15.

c. The storage gas included in rate base for the test year was not utilized by any of the subsidiaries; therefore, gas in storage should not be allocated to the subsidiaries.

d. The subsidiaries are financed with short-term, not long-term debt; therefore, unamortized debt should not be allocated to the subsidiaries.

e. Advances for construction relate solely to the operation of the utility; therefore, advances for construction should not be allocated to the subsidiaries.

WITNESS: John Brown

CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

13. Refer to Delta's Response to the Commission's Order of August 11, 199, 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 is 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.

RESPONSE:

The Commission had a longstanding practice prior to Delta's last rate case 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.

Because rate base and capital do not equal, Delta has tried to be consistent in using the percent of return in rate base that will only give it the same return as is in its proposed capital, thus the reason for using different returns on capital and rate base. As the rate base changed, the percent of return on rate base should have changed also in Item 26(b). Thus, the percent should be 9.2858% and not the same 9.3127% used. Item 26(b) is incorrect and should show no increase in operating income because capitalization did not change.

Sponsoring Witness:

John F. Hall

[4] $7,085,868 Requested Return / $76,728,462 Proposed Capital = 9.235%

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

14. Refer to Delta's Response to the Commision's Order of August 11, 1999, Item 27.

a. Reconcile the $1,551,279 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.

RESPONSE:

a. In reference to Item 27, the net TranEx Plant amount is $1,587,945. This amount is in agreement with the TranEx adjustment included in Delta's Response to Item 23. The amount stated above of $1,551,279 (TranEx Plant $4,046,127 - $2,494,848 TranEx Depreciation = $1,551,279) is incorrect. TranEx Plant on Item 27 is on line 8 as $4,044,291. The amount referred to as TranEx Plant $4,046,127, is on line 4 and stated as Delta Cushion Gas Account 117.

	Item 23	Item 27
Tranex Plant	4,044,291	4,044,291
Tranex CWIP	38,502	38,502
Tranex Depr	(2,494,848)	(2,494,848)
	1,587,945	1,587,945

b. Case Number 97-140 was prepared prior to purchase of Tranex and closing of deal. The $4,300,000 was an estimated figure and rounded to nearest hundred thousand. Actual amounts of assets acquired were adjusted at closing.

	12/31/98 Case No. 99-176	6/30/97 Case No. 97-140
Tranex Plant	5,014,489	4,273,931
Acquisition Adjustment	(1,045,704)	
Accum Prov for Gas Plt Adq Adj	75,506	
	4,044,291	4,273,931

SPONSORING WITNESS: John Brown

Delta Natural Gas Company, Inc.
Case No. 99-176
Item 15

15. Provide Tranex's 1998 balance sheet, income statement, statement of retained earnings, and cash flow statement.

Response:

See attached

Tranex does not have a Statement of Cash Flows, since it does not have any cash accounts.

Supporting Witness: John Brown

Tranex, Inc.
Balance Sheet
as of 12/31/98

Assets		
Gross Assets	4,082,793	
Depreciation	(2,494,848)	
Net Fixed Assets		1,587,945
Other Non-current Assets		
Current Assets		
Accounts Receivable	160,800	
Other	-	160,800
Total Assets		1,748,745
Liabilities		
Capitalization		
Common Stock	-	
APIC	1,000,000	
Retained Earnings (loss)	(114,525)	
Payable to Associated Companies	931,670	1,817,145
Current Liabilities		
Accounts Payable	-	
Accrued Taxes	(68,400)	
Other	-	(68,400)
Total Liabilities		1,748,745

Tranex, Inc.
Income Statement
for the year ended 12/31/98

Revenues

Other	-	-

Expenses

Oprations & Maint	326	
Rent Land & Land Rights	52,947	
Outside Services	278	
Insurance	-	
Depreciation	35,205	
Interest Expense	14,100	
Property Taxes	8,185	
Income Taxes (loss)	(41,800)	69,241

Net Income (loss)		**(69,241)**

Tranex, Inc.
Statement of Retained Earnings
for the year ended 12/31/98

Beginning Retained Earnings (loss)	(45,284)
:add Net Income (loss)	(69,241)
:less Dividends	-
Ending Retained Earnings (loss)	**(114,525)**

Delta Natural Gas Company, Inc.
Case No. 99-176
Item 16

16. Provide Enpro's 1998 balance sheet, income statement, statement of retained earnings, and cash flow statement.

Response:

See attached

Enpro does not have a Statement of Cash Flows, since it does not have any cash accounts.

Supporting Witness: John Brown

Enpro, Inc.
Balance Sheet
as of 12/31/98

Assets		
Gross Assets	2,097,722	
Depreciation	(817,443)	
Net Fixed Assets		1,280,279
Other Non-current Assets		412,862
Current Assets		
Accounts Receivable	(3,087)	
Other	-	(3,087)
Total Assets		**1,690,053**
Liabilities		
Capitalization		
Common Stock	100	
APIC	900	
Retained Earnings	215,236	
Payable to Associated Companied	1,231,901	1,448,137
Current Liabilities		
Accounts Payable	27,105	
Accrued Taxes	184,812	
Other	30,000	241,917
Total Liabilities		**1,690,053**

Enpro, Inc.
Income Statement
for the year ended 12/31/98

Revenues		
Gas Production	500,609	
Oil Production	20,427	
Other	42,534	563,571
Expenses		
Depletion	45,540	
Well Opr & Maint	22,449	
Royalties and Working Interest	85,735	
Outside Services	7,921	
Interest Expense	72,300	
Taxes - Non Income	11,410	
Income Taxes	124,800	370,154
Operating Income		193,417
Net Income from Subs		3,900
Net Income		**197,317**

Enpro, Inc.
Statement of Retained Earnings
for the year ended 12/31/98

Beginning Retained Earnings	17,919
:add Net Income	197,317
:less Dividends	-
Ending Retained Earnings	**215,236**

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.
(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) Th purchase price results in overall benefits in the financial and service aspects of Delta's operations.

RESPONSE:

a. Yes, See the breakdown of this number below: Note that the acquisition adjustment is negative. This is because Delta paid the fair value of the plant, which was significantly less than book value.

Plant A/C 6.367 – 6.371, 7.303	5,014,489
Accum Depr A/C 6.108.01, 7.111	(2,494,848)
CWIP A/C 6.107.01	32,502
Acquisition Adjustment 6.114	(1,045,704)
Accum Amort-AA 6.115	75,506
	1,587,945

b. The acquisition adjustment was a negative adjustment as the negotiated price was less than the book value of the plant. The purchase price resulted from arms-length negotiations. Costs after purchase did not result in costs exceeding book value. Delta operates TranEx as a part of its existing overall operation without significant added costs. There were no non-utility properties. The pipeline is used as an integral part of Delta's system to transport gas to storage at Canada Mountain and to transport gas to use in Delta's system.

This negative acquisition adjustment has resulted in a reduction in Delta's rate base relative to TranEx and Delta's customers thus benefit in this rate case by this adjustment.

Sponsoring Witness:

17. a John Brown
17. b Glenn R. Jennings

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

18. Provide all contracts and lease agreements between Delta and TranEx.

RESPONSE:

No contracts or other agreements between Delta and TranEx exist.

Sponsoring Witness:

Glenn R. Jennings

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

PSC Data Request Dated 9/14/99

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.

RESPONSE:

Delta has been recovering Deltran (Canada Mountain storage) costs through its quarterly GCR filings for several years as the field has been developed and completed. Otherwise, frequent and more costly rate cases would have been required.

Delta has had no rate on the TranEx pipeline since acquiring it. Commission staff discouraged filing for a separate rate until the EREX lease on TranEx expired. This lease expired after the end of the test year in this rate case. Delta has thus included TranEx in this current rate case as a pro forma adjustment to appropriately earn on it.

Delta was willing to seek a reasonable return on TranEx in a separate case on TranEx, but it was felt to be more economical to merge TranEx into Delta after the EREX lease terminated and just include TranEx with Delta in this current case. This also avoids a separate rate on TranEx on a stand alone basis.

Delta is willing to include TranEx in its GCR filings as is done with Canada Mountain if that is decided by the Commission to be the best solution. However, Delta believed the best approach on the TranEx pipeline was to include it with Delta in adjusting Delta's base rates and that is what Delta has proposed in this current rate case.

SPONSORING WITNESS:

Glenn R. Jennings

Notes

20

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

PSC Data Request Dated 9/14/99

20.

a. Describe the procedures that Delta uses to identify, assign and allocate costs to Canada Mountain and Tranex.

b. Provide all internal memorandum, correspondence, policy manuals and other documentation that discuss these procedures.

Response:

a. Delta and its subs are under common executive management. Delta's existing staff and facilities are used to perform functions for the subs as required (including Tranex and Canada Mountain). Administrative overheads are allocated to each subsidiary and to Canada Mountain, consistent to recommendations made in Delta's management audit (see attached recommendation and resolution). The following are allocated on the basis of <u>direct assignment</u> to all the subs (including Tranex and Canada Mountain):

- Base pay
- Vendor expenses
- Income taxes
- Taxes other than income taxes
- Interest charges
- Depreciation and depletion
- Outside service

b. See attached. Delta has no specific manuals, etc. relating only to this. Accounting for the subsidiaries is a part of Delta's internal accounting and account assignment. Delta is smaller and information is generally communicated directly in this regard.

Witness:

John Brown

DELTA NATURAL GAS CO. MEMO

Date: July 7, 1997

To: Marian, Kathy, Donna, Glenn, Johnny, Alan, John, Steve B.

From: John B.

Subject: Tranex Corporation Chart of Accounts

We have set up Tranex Corporation in our General Ledger Chart of Accounts as Company 6. Please review this first draft of the chart of accounts and make suggestions for changes/additions of accounts.

Thanks!

TRANEX CORPORATION, INC.

CHART OF ACCOUNTS
Date: 7/7/97

GENERAL LEDGER NUMBER AND DESCRIPTION
6-108-010 - PROV FOR DEPR PLANT IN SERVICE
6-114-000 - GAS PLANT ACQUISITION ADJUSTMENT
6-115-000 - ACCUM PROV FOR GAS PLANT ACQ ADJ
6-130-000 - CASH CLEARING
6-131-200 - SUBSIDIARY CASH CLEARING
6-142-000 - ACCOUNTS RECEIVABLE
6-143-000 - OTHER ACCOUNTS RECEIVABLE
6-143-010 - UNAMORT DISC ON INTANGIBLE ASSET-LEASE
6-146-000 - INTERCOMPANY CLEARING ACCOUNT
6-165-000 - PREPAYMENT
6-201-000 - COMMON STOCK
6-207-000 - PREMIUMS ON COMMON STOCK
6-216-000 - RETAINED EARNINGS
6-232-000 - ACCOUNTS PAYABLE
6-234-010 - PAYABLE TO DELTA NATURAL
6-234-020 - PAYABLE TO DELTA RESOURCES
6-234-030 - PAYABLE TO DELGASCO
6-234-040 - PAYABLE TO DELTRAN
6-236-010 - TAXES ACCRUED FEDERAL INCOME
6-236-020 - TAXES ACCRUED STATE INCOME
6-236-030 - TAXES ACCRUED STATE SALES
6-236-050 - TAXES ACCRUED PROPERTY
6-236-060 - TAXES ACCRUED SEVERANCE
6-236-070 - TAXES ACCRUED EST INCOME TAXES
6-367-000 - TRANSMISSION MAINS
6-368-000 - TRANSM COMPRESSOR STATION EQUIPMENT
6-369-000 - TRANSMISSION MEAS & REG STAT EQUIPMT
6-371-000 - OTHER EQUIPMENT - TELEMETERING
6-403-000 - DEPRECIATION EXPENSE
6-406-000 - AMORT OF GAS PLANT ACQ ADJ
6-408-000 - PROPERTY TAXES
6-409-010 - CURRENT FEDERAL INCOME TAX
6-409-020 - CURRENT STATE INCOME TAX
6-409-070 - ESTIMATED INTERIM INCOME TAXES
6-431-000 - INTEREST EXPENSE
6-489-000 - REVENUE FROM AFFILIATED CO'S
6-497-000 - REVENUE FROM OTHERS
6-886-000 - MNT STRUCTURES TRANS & DIST
6-887-000 - MNT TRANS & DIST MAINS PAYROLL
6-887-020 - MNT TRANS & DIST MAINS OTHER
6-889-000 - MNT REG STATIONS - TRANSM & DIST

TRANEX CORPORATION, INC.

CHART OF ACCOUNTS
Date: 7/7/97

GENERAL LEDGER NUMBER AND DESCRIPTION
6-898-010 - MNT TRANSP EQUIP EXPENSE
6-898-020 - MNT POWER OP EQUIP EXPENSE
6-900-010 - TRANS & DIST PAYROLL
6-900-020 - OPR TRANSPORTATION EXPENSES
6-923-000 - OUTSIDE SERVICES
6-924-000 - INSURANCE

COMPANY CORRESPONDENCE

TO: Alan, Butch, Steve, Jim N., Bobby, Jouett, Jonathan John B. and Kathy

FROM: Mitchell

DATE: October 13, 1995

SUBJECT: Canada Mountain Work Orders

Listed below are the seventeen work orders that have currently been issued for the Canada Mountain project:

WORK ORDER NUMBER	DESCRIPTION	ACCOUNT NUMBER
525-264	Install an 8″ aboveground valve in the Middlesboro Manchester 8″ pipeline north of Canada Mountain side valve	367
525-265	Rework and evaluate all six gas wells at Canada Mountain. Install new tubing and well heads as needed	352.2
525-266	Install 1,800 feet of 8″ steel pipeline from Well 119 to Well 21-1	353
525-267	Install a compressor station near Well 119	354
525-268	Install measurement, regulation and associated equipment at Well 119	355
525-269	Install measurement and associated equipment at Well 21-1	355
525-270	Install measurement and associated equipment at Well 18-1A	355
525-271	Install measurement and regulation equipment at the tie-in point of Canada Mountain to the Middlesboro-Manchester system located at the bottom of the hill at the old compressor site	355

WORK ORDER NUMBER	DESCRIPTION	ACCOUNT NUMBER
525-271	Install measurement and regulation equipment at the tie-in point of Canada Mountain to the Middlesboro-Manchester system located at the bottom of the hill at the old compressor site	355
525-272	Install telemetering to measurement and regulation station located at the bottom of the hill at Canada Mountain (Refer to Work Order Number 525-271)	357
525-273	Install measurement and regulation equipment near Well 119 and the compressor station at Canada Mountain master meter located at the top of the hill	355
525-274	Install telemetering at the measurement and regulation station at Well 119 for the master meter located at the top of the hill (Refer to Work Order Number 525-273)	357
525-275	Purchase six gas wells and associated equipment from Lonnie D. Ferrin	352.2
525-276	Purchase storage field pipeline from Lonnie D. Ferrin	353
525-277	Purchase remaining gas reserves from Lonnie D. Ferrin	352.3
525-278	Purchase storage rights from Lonnie D. Ferrin	352.1
525-279	Purchase compressor site from Fitzpatrick heirs	350.1
525-280	Purchase storage rights from Fitzpatrick heirs	352.1

mvr

DELTA NATURAL GAS COMPANY, INC.

MANAGEMENT AUDIT ACTION PLAN PROGRESS REPORT

DATE FILED: January 15, 1993

RECOMMENDATION NO.: IX-3 PRIORITY: High

PERSON RESPONSIBLE: Thomas A. Kohnle

RECOMMENDATION: Delta should implement a direct charge system for time spent and charged to the non-regulated subsidiaries.

__X__ The Company considers this action plan complete and requests that it be closed. The following items are addressed below:

- __X__ Date of completion - July 1, 1992
- __X__ Steps taken and improvements made
- __X__ Cost/benefit analysis

_____ The implementation of this action plan is still in progress. The steps taken and improvements made to date are detailed below.

_____ The Company does not agree with this recommendation for the reasons detailed in Section I below.

SECTION I - IMPLEMENTATION STEPS TO ACCOMPLISH RECOMMENDATION

Develop and implement a time reporting system for all employees who spend time working with Delta's subsidiaries.

SECTION II - ACTION TAKEN ON IMPLEMENTATION STEPS

Separate attachment? Yes.

The plan was completed July 1, 1992 when special timekeeping for general office personnel was implemented. Heretofore, the support has been established by discussions periodically with those individuals who may have spent time in service to the subsidiaries.

The resulting estimate of time was then used in allocating costs to the subsidiaries.

The time reports are being kept and data is being gathered to utilize this reporting as the basis for charges to the subsidiaries.

SECTION III - ANSWERS TO QUESTIONS OF COMMISSION STAFF

No questions asked.

SECTION IV - ACTIONS CONTEMPLATED PRIOR TO NEXT RESPONSE FILING

None.

SECTION V - COST/BENEFIT ANALYSIS

The cost to implement is minor and the benefit will be the time report documents to support the allocation of charges to the subsidiary companies.

	ONE TIME	RECURRING ANNUAL
COST	$0	Unable to quantify
BENEFIT	$0	Unable to quantify

COMPANY CORRESPONDENCE

Use Separate Sheet for Each Subject

Sheet No. 1 of 1

Date July 1, 19 92

TO All Officers FROM Tom

LOCATION LOCATION

SUBJECT Time Reporting - Subsidiary Companies

PLEASE REPLY PROMPTLY ☐
NO REPLY NECESSARY ☐

Our action plan in connection with the Management Audit Recommendation IX - 3 requires that we implement a time reporting system for all employees who spend time working directly for Delta's subsidiaries. Accordingly, we will utilize Form 201 - General Office Time Report to record such time except for those persons now completing Form 200 - Field Time Report. Refer to the attached Form 201 for the location to enter the data.

In addition to all officers, who may directly spend time performing services for the subsidiaries, other personnel in various departments may also spend time which relates to the subsidiaries. Except for the officers, all other persons are completing Form 201 - General Office time Report in accordance with Standard Practice AA 2-2.

All officers, effective July 1, 1992 are to begin recording any time they spend on behalf of the subsidiries on Form 201. In addition they will need to record the total hours worked each day to enable a percentage of time applicable to the subsidiaries to be obtained. The time can be segregated on the time report, if you desire, between the various type services you perform which may help answer questions that may arise.

The Transmission Department renders service to Enpro and is already indicating such time on a Field Time Report (Form 200) which is being charged directly, thru payroll distribution, to the subs.

Please discuss this additional time reporting with those persons in your areas who may perform services for the subsidiary companies. Any services performed for the subsidiaries which would also be performed for other Delta customers or suppliers are not chargeable to the subs, since tariff rates paid to Delta, by the subs, cover those services.

Please contact me with any questions you have in regard to the subsidiaries companies.

Tom

IPLOYEE SIGNATUR

DELTA NATUR AL GAS CO.

GENERAL OFFICE TIME REPORT

PERIOD ENDING

Description of Work or Project	1 / 16	2 / 17	3 / 18	4 / 19	5 / 20	6 / 21	7 / 22	8 / 23	9 / 24	10 / 25	11 / 26	12 / 27	13 / 28	14 / 29	15 / 30	31	TOTAL HOURS
I. OPERATIONS & MAINTENANCE																	
A. TIME OFF																	
B. ALL OTHER																	
II. CAPITALIZED TIME																	
III. CHARGEABLE SERVICES																	
RESOURCES																	
DELGASCO																	
DELTRAN																	
ENPRO																	
IV. SPECIAL STUDIES and/or PROJECTS																	
TOTAL HOURS																	

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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 1, 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.

RESPONSE:

a. Delta annualized the pay period ending December 31, 1998 because it reflected the current employees on payroll. If Delta had annualized the pay period of July 15, 1998 the pro forma salaries and wages would have been $6,022,185 compared to the $6,009,885 that was used.

		12/31/98		7/15/98
Total Wages		261,442.23		261,965.57
Overtime		(9,413.84)		(5,882.46)
Part-time		(1,616.50)		(5,369.00)
Salary Adj.				210.28
		250,411.89		250,924.39
	x	24	x	24
		6,009,885.36		6,022,185.36

b. See Attached

c. See Attached

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Employee #	(b) 2/1/98	(c) 7/1/98
80	31,500	32,400
200	35,100	36,200
220	60,900	62,600
260	24,200	24,800
405	56,700	58,500
520	86,800	89,700
620	26,800	27,500
760	48,100	49,500
820	34,000	34,900
840	54,300	55,500
980	27,700	28,600
1060	28,000	28,900
1130	26,600	27,500
3304	24,200	24,800
1240	86,300	89,200
1280	24,900	25,800
1340	69,700	71,800
1360	97,700	100,700
1420	50,800	52,600
3335	31,800	32,800
1560	150,000	154,500
1580	28,600	29,400
1600	45,700	47,000
1620	27,800	28,800
1843	26,700	27,600
1860	30,600	31,400
1880	25,100	25,500
1910	28,700	29,600
1925	32,200	33,200
1970	38,700	40,000
1975	23,400	24,100
2015	60,400	62,100
2210	26,400	27,300
2320	24,200	24,900
2340	37,500	38,700
2450	31,800	32,700
2480	32,000	32,900

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Employee #	(b) 2/1/98	(c) 7/1/98
2530	29,300	30,100
2545	28,700	29,500
2560	24,600	25,300
2660	56,500	58,100
2730	25,400	26,000
2735	33,800	35,100
2740	22,800	23,500
2980	31,800	32,900
3080	40,200	41,000
3160	25,500	26,200
3240	34,000	34,800
560	27,400	28,100
580	27,700	28,400
680	25,500	26,300
740	24,300	25,000
850	21,800	22,500
900	25,700	26,300
1500	27,500	28,200
1700	27,100	27,800
1740	26,700	27,500
1850	22,100	23,000
1980	24,800	25,700
2020	25,100	25,800
2080	23,700	24,400
2675	20,100	20,900
2860	27,800	28,600
2920	23,800	24,500
2940	27,500	28,300
3000	25,800	26,600
3100	25,400	26,000
3302	20,000	20,600
40	39,500	40,600
60	29,600	30,400
70	27,200	28,000
100	51,300	52,900
130	25,000	25,800
140	30,300	31,100
160	28,400	29,300

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Employee #	(b) 2/1/98	(c) 7/1/98
210	28,200	29,000
250	34,300	35,000
280	30,600	31,400
290	26,100	26,900
320	30,200	31,000
340	39,600	40,700
400	27,400	28,100
420	32,900	33,800
440	28,500	29,300
450	27,800	28,600
500	45,400	46,800
515	27,800	28,600
518	20,000	20,600
550	25,000	25,800
585	20,100	20,800
590	26,100	26,900
600	35,700	36,900
660	26,700	27,400
700	37,200	38,400
720	38,800	40,100
770	26,400	27,200
3303	24,000	24,700
780	34,000	34,900
800	29,200	30,000
855	24,500	25,200
870	27,100	27,700
880	33,300	34,200
965	20,000	20,600
1000	29,200	29,800
1010	29,500	30,500
1020	30,100	30,900
1040	30,800	31,600
1070	28,200	29,000
1080	41,900	43,100
1100	27,000	27,700
1120	25,200	26,100
1140	26,700	27,500
1160	25,400	25,800

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Employee #	(b) 2/1/98	(c) 7/1/98
1170	21,800	22,400
1220	33,500	34,200
3300	24,400	24,800
1260	27,900	28,800
1320	25,300	25,900
1400	42,200	43,300
1440	24,100	24,700
1480	28,000	28,800
1485	20,000	20,600
1510	28,100	28,900
3324	23,400	24,700
1540	30,400	31,300
1590	29,300	30,100
1680	27,300	28,300
1720	27,700	28,400
1750	28,500	29,300
1760	28,300	29,400
1780	30,400	31,300
1800	39,300	40,100
1855	24,000	24,800
1890	28,600	29,400
1895	26,600	27,400
1920	30,200	31,000
1922	19,900	20,500
1940	40,400	41,100
1950	26,300	27,100
2005	26,400	26,800
2010	30,700	31,700
2013	25,500	26,500
2030	35,100	35,600
3310	26,400	27,200
2047	24,500	25,100
2050	27,000	27,800
2120	33,900	34,800
2160	28,300	29,100
2180	27,900	28,800
2185	28,000	28,800
3333	19,800	20,400

DELTA NATURAL GAS COMPANY INC

CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

	(b)	(c)
Employee #	2/1/98	7/1/98
2220	49,800	51,200
2240	41,900	43,100
2260	38,600	39,600
2280	28,100	28,900
2290	22,800	23,600
2360	32,900	33,900
2420	47,600	49,400
3301	26,600	27,400
2460	59,900	61,600
2500	30,300	31,000
2550	31,100	32,100
3309	19,800	20,400
2615	24,600	25,300
2620	38,900	39,900
2680	34,600	35,400
2720	28,300	29,100
3311	19,800	20,400
2782	30,800	31,600
2800	26,000	26,800
2820	40,900	42,000
2840	29,100	30,100
2870	24,200	25,000
2880	29,400	30,200
2900	28,400	29,100
2960	31,300	32,100
2985	25,100	25,900
3060	36,300	37,400
3120	28,000	28,700
3260	28,400	29,300
3323	26,400	27,000
3336	24,000	24,300
Job Vacant	19,800	20,200
	5,873,600	6,042,900

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.

RESPONSE:

a. See Attached

b. Delta adjusted its pro forma salaries and wages consistent with the filing of Rate Case No. 97-066. If Delta had made an adjustment to reflect the test period allocations to the clearing accounts it would have been an adjustment of $26,626.

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY INC
CASE NO 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

a. Re Page 355 of 1998 PSC Annual Report

A/C 1.926.01 - Time Off Payroll (Field Only)				442,182
Total Field Hours	252,694			
Time Off Hours	(30,498)			
Net	222,196			
Total Construction Hours	57,354	25.8%		
A/C 1.926.01	442,182 X 25.8% =		114,083	
A/C 1.920.01 - Administrative Payroll		1,985,724		
35% to Construction			695,003	
			809,086	
	Say		809,000	
	Est to Subs		6,000	
			815,000	

23

DELTA NATURAL GAS COMPANY INC.
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.

RESPONSE:

a. See Attached

b. See Attached

c. The total allocation to the clearing accounts should be $824,700. Refer to Item 23b for the calculation of $818,700 plus an additional $6,000 for the Subsidiaries. We also used overtime and part-time in this calculation which Delta excluded from its pro forma salaries and wages.

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY INC.
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

Delta Natural Gas Company, Inc.
CASE NO. 99-176
Pro Forma Salaries and Wages

Item 23(a)

Employee Number	Wages Effective 2/1/98	Wages Effective 7/1/98	Hours Worked Regular	Hours Worked Overtime	Pro Forma Salaries and Wages Regular	Pro Forma Salaries and Wages Overtime	Pro Forma Salaries and Wages Total
80	31,500	32,400	2088.0		32,400		32,400
200	35,100	36,200	2101.5		36,200		36,200
220	60,900	62,600	2117.0		62,600		62,600
260	24,200	24,800	2088.0		24,800		24,800
405	56,700	58,500	2088.0		58,500		58,500
520	86,800	89,700	2088.0		89,700		89,700
620	26,800	27,500	2088.0		27,500		27,500
760	48,100	49,500	2088.0		49,500		49,500
820	34,000	34,900	2100.0		34,900		34,900
840	54,300	55,500	2261.5		55,500		55,500
980	27,700	28,600	2088.0		28,600		28,600
1060	28,000	28,900	2150.0		28,900		28,900
1130	26,600	27,500	2088.0		27,500		27,500
3304	24,200	24,800	2088.0		24,800		24,800
1240	86,300	89,200	2088.0		89,200		89,200
1280	24,900	25,800	2088.0		25,800		25,800
1340	69,700	71,800	2088.0		71,800		71,800
1360	97,700	100,700	2212.5		100,700		100,700
1420	50,800	52,600	2176.0		52,600		52,600
3335	31,800	32,800	2163.0		32,800		32,800
1560	150,000	154,500	2281.0		154,500		154,500
1580	28,600	29,400	2087.0		29,400		29,400
1600	45,700	47,000	2100.5		47,000		47,000
1620	27,800	28,800	2180.0		28,800		28,800
1843	26,700	27,600	2239.5		27,600		27,600
1860	30,600	31,400	2088.0		31,400		31,400
1880	25,100	25,500	2088.0		25,500		25,500
1910	28,700	29,600	2281.0		29,600		29,600
1925	32,200	33,200	2150.5		33,200		33,200
1970	38,700	40,000	2259.0		40,000		40,000
1975	23,400	24,100	2088.0		24,100		24,100
2015	60,400	62,100	2157.0		62,100		62,100
2210	26,400	27,300	2088.0	3	27,300	59	27,359

2320	24,200	24,900	2088.0		24,900		24,900
2340	37,500	38,700	2088.0		38,700		38,700
2450	31,800	32,700	2138.0		32,700		32,700
2480	32,000	32,900	2101.0		32,900		32,900
2530	29,300	30,100	2088.0		30,100		30,100
2545	28,700	29,500	2088.0	6	29,500	128	29,628
2560	24,600	25,300	2088.0		25,300		25,300
2660	56,500	58,100	2088.0		58,100		58,100
2730	25,400	26,000	2088.0		26,000		26,000
2735	33,800	35,100	2234.0		35,100		35,100
2740	22,800	23,500	2088.0	1.5	23,500	25	23,525
2980	31,800	32,900	2211.0		32,900		32,900
3080	40,200	41,000	2102.5		41,000		41,000
3160	25,500	26,200	2104.0		26,200		26,200
3240	34,000	34,800	2088.0	33	34,800	828	35,628
560	27,400	28,100	2088.0	1	28,100	20	28,120
580	27,700	28,400	2088.0	54	28,400	1,106	29,506
680	25,500	26,300	2088.0	1.5	26,300	28	26,328
740	24,300	25,000	1416.0		16,923		16,923
850	21,800	22,500	2088.0		22,500		22,500
900	25,700	26,300	2088.0	1	26,300	19	26,319
1500	27,500	28,200	2088.0	3	28,200	61	28,261
1700	27,100	27,800	1648.0	6	21,919	120	22,039
1740	26,700	27,500	2088.0		27,500		27,500
1850	22,100	23,000	2088.0		23,000		23,000
1980	24,800	25,700	2088.0	9	25,700	167	25,867
2020	25,100	25,800	2088.0	52	25,800	967	26,767
2080	23,700	24,400	2088.0		24,400		24,400
2675	20,100	20,900	2088.0	13	20,900	196	21,096
2860	27,800	28,600	2088.0	6.5	28,600	134	28,734
2920	23,800	24,500	2088.0	9.5	24,500	168	24,668
2940	27,500	28,300	2088.0	1	28,300	20	28,320
3000	25,800	26,600	2088.0	8.5	26,600	163	26,763
3100	25,400	26,000	2088.0	3	26,000	56	26,056
3302	20,000	20,600	2088.0	123.5	20,600	1,835	22,435
40	39,500	40,600	2142.0		40,600		40,600
60	29,600	30,400	2088.0	74	30,400	1,622	32,022
70	27,200	28,000	2088.0	55	28,000	1,111	29,111
100	51,300	52,900	2088.0		52,900		52,900
130	25,000	25,800	2088.0	114	25,800	2,121	27,921
140	30,300	31,100	2088.0	37.5	31,100	841	31,941
160	28,400	29,300	2088.0	40	29,300	845	30,145
210	28,200	29,000	2088.0	94	29,000	1,966	30,966
250	34,300	35,000	2008.0	117	33,652	2,953	36,605
280	30,600	31,400	2088.0	158	31,400	3,578	34,978
290	26,100	26,900	2088.0	99	26,900	1,920	28,820
320	30,200	31,000	2088.0	114	31,000	2,548	33,548
340	39,600	40,700	2102.0		40,700		40,700
400	27,400	28,100	2088.0	94	28,100	1,905	30,005
420	32,900	33,800	2088.0	47	33,800	1,146	34,946
440	28,500	29,300	2088.0	195.5	29,300	4,131	33,431

450	27,800	28,600	2088.0	78	28,600	1,609	30,209
500	45,400	46,800	2150.0		46,800		46,800
515	27,800	28,600	2008.0	51	28,600	1,052	29,652
518	20,000	20,600	2088.0	121	20,600	1,797	22,397
550	25,000	25,800	2088.0	193	25,800	3,591	29,391
585	20,100	20,800	2088.0	76	20,800	1,140	21,940
590	26,100	26,900	2088.0	50	26,900	970	27,870
600	35,700	36,900	2088.0	75	36,900	1,996	38,896
660	26,700	27,400	2088.0	65	27,400	1,284	28,684
700	37,200	38,400	2088.0	125	38,400	3,462	41,862
720	38,800	40,100	2088.0		40,100		40,100
770	26,400	27,200	2088.0	39	27,200	765	27,965
3303	24,000	24,700	2088.0	105	24,700	1,870	26,570
780	34,000	34,900	2088.0	44	34,900	1,107	36,007
800	29,200	30,000	2088.0	187	30,000	4,046	34,046
855	24,500	25,200	2088.0	92	25,200	1,672	26,872
870	27,100	27,700	1712.0	39.5	22,692	789	23,481
880	33,300	34,200	2088.0	91	34,200	2,244	36,444
965	20,000	20,600	2088.0	71	20,600	1,055	21,655
1000	29,200	29,800	2088.0	75	29,800	1,612	31,412
1010	29,500	30,500	2088.0	121	30,500	2,661	33,161
1020	30,100	30,900	2088.0	37	30,900	824	31,724
1040	30,800	31,600	2088.0		31,600		31,600
1070	28,200	29,000	2008.0	24	29,000	502	29,502
1080	41,900	43,100	2107.0		43,100		43,100
1100	27,000	27,700	2088.0	97	27,700	1,938	29,638
1120	25,200	26,100	2088.0	57	26,100	1,073	27,173
1140	26,700	27,500	2088.0	96.5	27,500	1,914	29,414
1160	25,400	25,800	2008.0	55	24,806	1,023	25,829
1170	21,800	22,400	2088.0	92	22,400	1,486	23,886
1220	33,500	34,200	2088.0	157	34,200	3,872	38,072
3300	24,400	24,800	595.0	10.5	6,979	185	7,164
1260	27,900	28,800	2088.0	38	28,800	789	29,589
1320	25,300	25,900	2096.0	2	25,900	37	25,937
1400	42,200	43,300	2385.0	7.5	43,300	234	43,534
1440	24,100	24,700	2088.0		24,700		24,700
1480	28,000	28,800	2088.0	5	28,800	104	28,904
1485	20,000	20,600	2088.0	88	20,600	1,307	21,907
1510	28,100	28,900	2072.0	130.5	28,677	2,720	31,397
3324	23,400	24,700	2088.0	86	24,700	1,532	26,232
1540	30,400	31,300	2088.0	58	31,300	1,309	32,609
1590	29,300	30,100	2088.0	108	30,100	2,344	32,444
1680	27,300	28,300	2088.0	68	28,300	1,388	29,688
1720	27,700	28,400	2088.0	43	28,400	881	29,281
1750	28,500	29,300	2008.0	61	29,300	1,289	30,589
1760	28,300	29,400	2088.0	84	29,400	1,781	31,181
1780	30,400	31,300	2088.0	36	31,300	813	32,113
1800	39,300	40,100	2097.0		40,100		40,100
1855	24,000	24,800	2088.0	204	24,800	3,649	28,449
1890	28,600	29,400	2088.0	14	29,400	297	29,697
1895	26,600	27,400	2088.0	128	27,400	2,529	29,929

1920	30,200	31,000	2088.0	2	31,000	45	31,045
1922	19,900	20,500	2088.0	85	20,500	1,257	21,757
1940	40,400	41,100	2111.0		41,100		41,100
1950	26,300	27,100	2088.0	139	27,100	2,716	29,816
2005	26,400	26,800	1648.0	4	21,130	77	21,207
2010	30,700	31,700	2088.0	167	31,700	3,818	35,518
2013	25,500	26,500	2088.0	82	26,500	1,567	28,067
2030	35,100	35,600	2111.0	25	35,600	642	36,242
3310	26,400	27,200	2088.0	81	27,200	1,589	28,789
2047	24,500	25,100	2088.0	77	25,100	1,394	26,494
2050	27,000	27,800	2088.0	33	27,800	662	28,462
2120	33,900	34,800	2088.0	51	34,800	1,280	36,080
2160	28,300	29,100	2088.0	95	29,100	1,994	31,094
2180	27,900	28,800	2088.0	79	28,800	1,641	30,441
2185	28,000	28,800	1249.5	29	17,190	602	17,792
3333	19,800	20,400	2088.0	106	20,400	1,559	21,959
2220	49,800	51,200	2201.5		51,200		51,200
2240	41,900	43,100	1437.0		29,610		29,610
2260	38,600	39,600	2108.0		39,600		39,600
2280	28,100	28,900	2088.0	33	28,900	688	29,588
2290	22,800	23,600	2088.0	94	23,600	1,600	25,200
2360	32,900	33,900	2088.0	165	33,900	4,034	37,934
2420	47,600	49,400	2219.0		49,400		49,400
3301	26,600	27,400	2088.0	113.5	27,400	2,243	29,643
2460	59,900	61,600	2379.0		61,600		61,600
2500	30,300	31,000	2088.0	63	31,000	1,408	32,408
2550	31,100	32,100	2088.0	93.5	32,100	2,164	34,264
3309	19,800	20,400	2088.0	78	20,400	1,147	21,547
2615	24,600	25,300	2088.0	94	25,300	1,715	27,015
2620	38,900	39,900	2097.0		39,900		39,900
2680	34,600	35,400	2088.0	95	35,400	2,425	37,825
2720	28,300	29,100	2088.0	94	29,100	1,973	31,073
3311	19,800	20,400	2088.0	85.5	20,400	1,258	21,658
2782	30,800	31,600	2088.0	236	31,600	5,378	36,978
2800	26,000	26,800	2088.0	61	26,800	1,179	27,979
2820	40,900	42,000	2113.0		42,000		42,000
2840	29,100	30,100	2088.0	74	30,100	1,606	31,706
2870	24,200	25,000	2088.0	21	25,000	379	25,379
2880	29,400	30,200	2088.0	166	30,200	3,615	33,815
2900	28,400	29,100	2088.0	83	29,100	1,742	30,842
2960	31,300	32,100	2088.0	52	32,100	1,204	33,304
2985	25,100	25,900	2088.0	89	25,900	1,662	27,562
3060	36,300	37,400	2314.0		37,400		37,400
3120	28,000	28,700	2088.0	166	28,700	3,436	32,136
3260	28,400	29,300	2088.0	75	29,300	1,585	30,885
3323	26,400	27,000	2009.0	59	27,000	1,149	28,149
3336	24,000	24,300	1352.0	34	15,701	596	16,296
3331	19,800	20,200	1352.0	8	13,052	117	13,168
	5,873,600	6,042,900	378434.5	8,248	5,957,030	168,472	6,125,502

3344		24300	184.0	5	2,149	87.62	2,237
3339		24300	1024.0	67	11,962	1,174.04	13,136
3314	26400		289.3	16	3,672	305	3,977
2700	44000		381.0		8,059		8,059
			380312.8	8,336	5,982,872	170,039	6,152,911
Part-time							
3317			264.0		1,848		1,848
3343			408.0	5	2,856	53	2,909
3342			412.0	6	2,884	63	2,947
2865			963.0	2	6,741	21	6,762
3338			810.0	0.5	6,480	6	6,486
3337			964.0		6,748		6,748
3322			312.0		2,184		2,184
3327			998.0		6,986		6,986
3334			24.0		144		144
3325			328.0		2,296		2,296
3326			210.0		1,470		1,470
625			958.0		8,143		8,143
3340			420.0		2,940		2,940
3312			800.0		5,153		5,153
3341			416.0		2,912		2,912
2005			124.0		744		744
			388,723.78	8,349.5	6,043,401	170,181	6,213,582

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
PSC DATA REQUEST DATED SEPTEMBER 14, 1999

B. FERC Form No. 2 (1998) -Pg 355

Construction	767,796 / 6,125,333 =	12.5%
Administrative	1,985,724 / 6,125,333 =	32.4%

Pro Forma Salaries and Wages Capitalized

Construction	6,213,582 x 12.5% =			776,698
*A/C 1.926.01	442,182 x 25.8% =		114,083	
Administrative	6,213,582 x 32.4% =	2,013,201		
		x 35%		
			704,620	
			818,703	
				818,700
Capitalized Pro Forma Wages				1,595,398

Note: This calculation includes overtime and part-time which Delta did not include in its pro forma salaries and wages.

Delta Natural Gas Company, Inc.
Case No. 99-176
Item 24

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 description of the costs included in the account.

RESPONSE:

Account Number	GL Name/ Description
1.816.01	CM Wells Expenses - Payroll
1.816.02	CM Wells Expenses - Misc.
1.818.01	CM Compressor Station Expense - Payroll
1.818.02	CM Compressor Station Expense - Misc.
1.821.00	CM Purification of Natural Gas
1.825.00	CM Storage Well Royalties / Rents
1.832.02	CM Maintenance of Reservoirs and Wells - Misc.
1.833.02	CM Maintenance of Lines - Misc.
1.834.01	CM Maintenance of Compressor Station Equipment - Payroll
1.834.02	CM Maintenance of Compressor Station Equipment - Misc.
1.835.01	CM Maintenance of Measurement and Regulator Station Equipment - Payroll
1.835.02	CM Maintenance of Measurement and Regulator Station Equipment - Misc.
1.837.02	CM Maintenance of Other Equipment - Misc.

Witness: John Brown

Delta Natural Gas Company, Inc.
Case No. 99-176
Item 25

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 description of each expense item.

RESPONSE:

Account Number **GL Name/ Description**

1.913.00 Advertising
All amounts are included in the balance of $10,775.10. These charges are for forms of advertising (mainly newspaper).

1.930.10 Public & Community Relations
All amounts are included in the balance of $16,885.96. All charges to this account are items to improve the image of the utility, in the eyes of the public.

1.930.11 Conservation Program
All amounts are included in the balance of $48,913.00. The conservation program is a builder incentive program with three categories, all which provide value and concern for the environment. This program partially reimburses the customer for using energy efficient and conservation appliances and natural gas furnaces.

1.930.12 Lobbying Expenditures
All amounts are included in the balance of $4,279.08

1.930.04 Marketing

All amounts are included in the balance of $37,869.02. This account includes incentives and items given away to promote and encourage use of natural gas.

1.920.01 Administrative Payroll
This amount only includes $24,000 which is the operating expense disallowed in the previous rate case. Every month $2,000 of a note owed to Delta by the president is forgiven as part of his compensation. This $24,000 was removed in error and should be included in allowable expenses in this current case. The amount not reflected in Item 30 - c is $1,982, 502.

Witness: John Brown

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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].

RESPONSE:

In Case No. 97-066 it had been six (6) years between Delta's cases. In Case 99-176 it has been only two (2) years between this case and Delta's prior case, thus the reason to use a 3-year amortization period for the expenses in this case.

Sponsoring Witness:

John F. Hall

[7] Case No. 97-066, An Adjustment of the General Rates of Delta Natural Gas Company (December 8, 1997).

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

PSC Data Request Dated 9/14/99

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.	1.282.02 – Def Inc Tax Pension Plan	$	(567,200)
b.	1.282.03 – Def Inc Tax Stock Plan	$	22,600
c.	1.282.06 – Def Inc Tax Annual Leave	$	153,500
d.	1.282.08 – Def Inc Tax Amort Ferrin Prom Note	$	16,200
e.	1.282.09 – Def Inc Taz Net Unbilled Rev	$	670,100
f.	1.282.11 – Def Inc Tax Bad Debt Res	$	47,300
g.	1.283.01 – Def Tax Regulatory Inc Tax	$	(500)
h.	1.283.02 – Def Tax Regulatory ITC	$	392,500

Response:

The Company agrees that the exact same ADIT components as allowed by the PSC in the prior case should be used in the current case. As detailed in the AG's 8/11/99 item 19, this amount would be $9,103,630.

Witness:

John Brown

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

PSC Data Request Dated 9/14/99

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.

Response:

Delta uses 39.445% which is an effective rate which includes both the state and federal statutory rates.

Witness:

John Brown

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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?

RESPONSE:

No.

Sponsoring Witness:

John F. Hall

Notes

DELTA NATURAL GAS COMPANY INC
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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.

RESPONSE:

The decrease in Delta's common equity was primarily due to lower earnings from warmer than normal weather and an increase in dividends from a stock offering completed in October 1988.

The decrease in long-term debt was due to the redemption by holders of Delta's 8-5/8% Debentures.

The increase in short-term debt was caused by several factors. Delta's sales are seasonal in nature, and the largest proportion of cash is received during the winter months when sales volumes increase considerably. During non-heating months, cash needs for operations and construction are partially met through short-term borrowings. Most construction activity takes place during the non-heating season because of more favorable weather conditions, thus increasing seasonal cash needs. Delta generated only $3.4 million of cash flow but had capital expenditures of $5.8 million, dividends of $1.7 million and long-term debt repayments, thus, the increase in short-term debt.

Sponsoring Witness:

John F. Hall

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 the equity component?

RESPONSE:

a. Delta's response to Item 2 of the Commission's July 15, 1999 Order demonstrates a steady erosion in the equity component of Delta's capital structure. 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. 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.

b. One thing is certain is that Delta will not be able to increase the equity component of its capital structure if its earned returns are not greater than it has experienced over the last 10 years. The rates in effect during that period combined with a number of other factors have resulted in earned returns that have led to an almost continual decline in the equity component of Delta's capital structure. Delta's management would like to reverse this trend, but must have sufficient resources to do so. Like most matters that are essentially management decisions, the Commission can express its preferences in the final order in this proceeding and take action in later proceedings if it does not believe that Delta's management has acted accordingly. It is the nature of regulation that most of the corrective action that the Commission can take is after an event has occurred. At this point in time, it is necessary for the Commission to trust that Delta will take appropriate actions to correct the trend in its equity component if resources are available.

WITNESS: Martin Blake

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.

RESPONSE:

Delta's budgets were completed before this rate case was planned and filed.

Sponsoring Witness:

John F. Hall

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

33. State Delta's current short-term debt cost rate.

RESPONSE:

Delta's current short-term debt cost rate as of September 21, 1999 is 5.51%.

Sponsoring Witness:

John F. Hall

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST DATED SEPTEMBER 14, 1999

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.

RESPONSE:

It should be 9.235% for the overall cost rate of capital. 9.3127% is the return needed for rate base to equal a 9.235% return on capital.

Sponsoring Witness:

John H. Hall

35. Refer to Delta's response to the Commission 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?

RESPONSE:

Currently, the Commission uses a methodology of weather normalizing billing units in determining rates for natural gas distribution companies. However, the Commission has not allowed Delta to weather normalize in applying rates. This inconsistency between rate determination and rate application exposes Delta to financial risk resulting from the vagaries of weather. Because of its small size and low equity component, there is a magnified effect of weather on Delta's earned returns. The methodology of weather normalizing billing units in determining rates only produces a fair result if there is no upward or downward trend in temperatures. If there is an upward trend in temperatures, there is a good chance that a natural gas utility would underearn when the rates were subsequently implemented. If there is a downward trend in temperatures, there is a good chance that a natural gas utility would overearn when the rates were subsequently implemented. During recent years, it appears that there has been an upward trend in the temperatures experienced in this area, with the end result that Delta has been underearning, as evidenced by the 10.1% earned return that Delta has averaged over the last ten years as shown on page 2 of Exhibit MJB-2. The WNA tariff would provide Delta with an opportunity to earn the return that the Commission has authorized regardless of any trend in temperatures. This would likely stabilize Delta's earned returns and, if these earned returns are stabilized at a sufficiently high level, Delta will have the resources available to begin rebuilding the equity component of its capital structure.

How analysts would view the implementation of the WNA tariff would depend on other factors in the rate case. Although stability of earnings is generally regarded by analysts as good, it may not be viewed positively if it occurs at a low level of earnings. It is difficult to isolate one issue and state how analysts will view that single factor. Analysts will assess the final order in its entirety before deciding whether it will help Delta reverse its "difficult earnings outlook".

WITNESS: Martin Blake

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)?

RESPONSE:

The material that I obtained for SIC Code 4924 from the Ibbotson web site, which included Delta in its panel of the 27 natural gas distribution companies, did not include an individual calculation of the discounted cash flow estimated return on equity for Delta. It included only composite information for the panel of 27 companies.

WITNESS: Martin Blake

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 upon the highest beta coefficient of 0.80. Assuming the lowest reported beta coefficient was 0.02, would 11.88 percent be the more appropriate return on equity to use when analyzing Delta's required return on equity?

RESPONSE:

Assuming a beta coefficient of 0.02 for Delta would result in an estimated return on equity of 6.24% before adding the size premium, calculated as:

$k = 6.08 + 0.02 \times 8.0 = 6.24$

After adding the size premium of 2.6%, the estimated return on equity would be 8.84%.

However, a beta coefficient of 0.02 would imply that there was almost no systematic risk and that the estimated return on equity for Delta would be approximately equal to the risk free rate. To assume that Delta's return on equity should approximate the risk free rate is unreasonable given Delta's existing financial condition and its experience regarding earned returns in recent years. As I stated in my Direct Testimony, I would recommend using a 11.9% return on equity only if an imputed capital structure is utilized. If an imputed capital structure is not utilized, I recommend using a 13.9% return on equity that includes a leverage premium to compensate for Delta's low equity component relative to other natural gas utilities. I believe that the Commission must utilize either an imputed capital structure or include a leverage adjustment to account for Delta's low level of equity in order to meet the requirements established by the U.S. Supreme Court in the Hope and Bluefield cases.

WITNESS: Martin Blake

Notes

DELTA NATURAL GAS COMPANY
CASE NUMBER 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.

RESPONSE:

a.

Net Investment in Enpro	216,236
Receivable from Enpro	1,231,901
Current Liabilities	241,917
Account Receivables	3,087
Non-Current Assets	(412,862)
Enpro Net Plant	1,280,279

b. See Attached

c. The approach of using the net plant amount is consistent with and approved in Delta's prior case.

d. Delta used the same approach in the current case as it used in the prior case.

SPONSORING WITNESS: JOHN BROWN

DELTA NATURAL GAS CO., INC. AND SUBSIDIARIES

Balance Sheet-Enpro - Detail

For Period Ending: December 31, 1998

	Current Y-T-D Amount	Last Year Y-T-D Amount	Current Y-T-D (-) Last Y-T-D Amount
ASSETS			
FIXED ASSETS			
5.325.0300 MINERAL RIGHTS	43,077.20	43,077.20	.00
5.325.2100 PRODUCTION LEASEHOLDS - GAS	1,983,657.50	1,983,657.50	.00
5.325.2300 WORKING INTEREST INVESTMENT	17,269.00	15,494.00	1,775.00
5.331.0200 OIL WELL EQUIPMENT	53,718.03	53,718.03	.00
Gross Assets	2,097,721.73	2,095,946.73	1,775.00
5.111.0000 PROVISION FOR DEPLETION	817,442.71CR	771,902.83CR	45,539.88CR
Depletion	817,442.71CR	771,902.83CR	45,539.88CR
Net Fixed Assets	1,280,279.02	1,324,043.90	43,764.88CR

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE:

a. See schedule attached.

b.

	Account Description	Amount
36501	Transmission Land and Land Rights	10,000
36502	Transmission Rights of Way	227,267
367	Transmission Mains	4,051,497
368	Transm Compressor Stat Equipmt	519,600
369	Transm Meas & Reg Stat Equipmt	145,142
371	Telemetering Equipment	60,982
114	Gas Plant Acquisition Adjustment	(1,045,704)
115	Accumulated Provision for Gas Plant Adjustmt	75,504
	Total Tranex Plant	4,044,289
10701	Construction Work In Progress	38,502
10801	Provision for Depreciation Plant In Service	2,494,848

SPONSORING WITNESS: JOHN BROWN

Tranex, Inc.
Selected Balance Sheet Balances
for the year ended 12/31/98

Gross Assets	4,007,287	
Depreciation	(2,419,344)	
Net Fixed Assets		**1,587,943**
Capitalization		
Common Stock	-	
APIC	(1,000,000)	
Retained Earnings	45,284	
Earnings Year to Date	69,241	
Payable to Associated Companies	(504,706)	**(1,390,181)**

* see The Attorney General's Supplemental Request for Information number 3 for a discussion of Tranex's merge into Delta Natural

Notes

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

AG DATA REQUEST
Dated 9/4/99

3. With regard to 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.

RESPONSE:

a. The Tranex plant is a 43-mile steel pipeline that extends from Madison County to Clay County. The pipeline is used for system supply and storage. This pipeline is useful in serving the ratepayers as to allow Delta to purchase gas in the summer when gas is cheaper and use in the winter when gas prices are more. This line also connects Delta's system to the Richmond area.

b. Effective 4/99, Delta merged Tranex into the regulated companyfor the reasons listed in a).

WITNESS: John Brown

Notes

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

AG DATA REQUEST
Dated 9/4/99

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 and in which filing schedule or workpaper are these revenues reflected? If not, why not?

RESPONSE:

Tranex did not generate revenues. See 5. for discussion of Tranex expenses.

WITNESS: John Brown

Notes

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

AG DATA REQUEST
Dated 9/4/99

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 work paper these expenses and taxes are reflected.

RESPONSE:

The expenses should have been included in Delta's filing requirements. This was an oversight. They should have been included for the reasons stated in 3.

WITNESS: John Brown

Notes

6

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE: See Attached Schedule

SPONSORING WITNESS: JOHN BROWN

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 6:

LINE NUMBER	MONTH ENDED	A/C 107 CONSTR WIP	BALANCE IN ACCTS PAYABLE A/C 107 CONSTR WIP
1	Dec-97	3,217,053	417,952
2	Nov-97	3,030,529	437,765
3	Oct-97	2,969,770	513,708
4	Sep-97	3,407,489	653,384
5	Aug-97	3,659,578	741,644
6	Jul-97	3,146,144	360,829
7	Jun-97	2,285,782	360,946
8	May-97	2,273,894	368,809
9	Apr-97	2,034,753	153,805
10	Mar-97	1,421,990	155,054
11	Feb-97	2,324,827	111,812
12	Jan-97	1,889,310	266,656
13	Dec-96	1,350,672	562,585
14	TOTAL	33,011,791	5,104,949
15	AVERAGE	2,539,369	392,688

Notes

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE: See Attached Schedules

SPONSORING WITNESS: JOHN BROWN

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 7: Response to Attorney General's Item 9 was incorrect. See corrected schedule below. Amounts were entered on previous schedule as if dates were ascending instead of descending. Difference between PSC Data Request 12 and AG-9 is Canada Mountain CWIP. See next schedule.

LINE NUMBER	MONTH ENDED	A/C 107 CWIP	MONTH ENDED	A/C 107 CWIP	
1	Dec-97	3,217,053	Dec-99	978,000	Estimate
2	Nov-97	3,030,529	Nov-99	1,131,100	Estimate
3	Oct-97	2,969,770	Oct-99	1,199,400	Estimate
4	Sep-97	3,407,489	Sep-99	1,183,700	Estimate
5	Aug-97	3,659,578	Aug-99	1,282,400	Estimate
6	Jul-97	3,146,144	Jul-99	1,559,200	Estimate
7	Jun-97	2,285,782	Jun-99	823,614	
8	May-97	2,273,894	May-99	612,963	
9	Apr-97	2,034,753	Apr-99	1,095,954	
10	Mar-97	1,421,990	Mar-99	1,816,935	
11	Feb-97	2,324,827	Feb-99	1,408,560	
12	Jan-97	1,889,310	Jan-99	993,964	
13	Dec-96	1,350,672	Dec-98	1,169,046	
14	Nov-96	2,928,671			
15	Oct-96	1,887,824			
16	Sep-96	657,134			
17	Aug-96	3,872,094			
18	Jul-96	2,559,800			
19	Jun-96	1,077,283			
20	May-96	1,830,021			
21	Apr-96	1,021,529			
22	Mar-96	313,831			
23	Feb-96	1,150,739			
24	Jan-96	517,136			
25	Dec-95	121,319			

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 7:

LINE NUMBER	MONTH ENDED	PSC DATA REQUEST 12 A/C 107 CWIP	LESS CANADA MTN CWIP	AG ITEM 9 A/C 107 CWIP WITHOUT CANADA MTN
1	Dec-96	2,533,593	1,182,921	1,350,672
2	Nov-96	4,138,760	1,210,089	2,928,671
3	Oct-96	2,721,707	833,883	1,887,824
4	Sep-96	1,374,577	717,443	657,134
5	Aug-96	5,649,898	1,777,804	3,872,094
6	Jul-96	4,291,969	1,732,169	2,559,800
7	Jun-96	2,757,884	1,680,601	1,077,283
8	May-96	3,235,746	1,405,725	1,830,021
9	Apr-96	2,030,405	1,008,876	1,021,529
10	Mar-96	880,164	566,333	313,831
11	Feb-96	1,854,865	704,126	1,150,739
12	Jan-96	918,717	401,581	517,136
13	Dec-95	472,510	351,191	121,319
14	TOTAL	32,860,794	13,572,742	19,288,052
15	AVERAGE	2,527,753	1,044,057	1,483,696

Notes

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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)

RESPONSE:

a.

Tranex Plant	5,014,489	5,014,489
Plant Acq Adjustment		(1,045,704)
Accum Prov for Gas Plt Acq Adj		75,506
Total	5,014,489	4,044,291

b. CWIP should not have been reflected on this report. In our haste to report data this was an oversite and error.

   See Corrected Schedule attached

SPONSORING WITNESS: JOHN BROWN

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

Line Number	Response to Item 8			Plant	Depr Rate	Annualized Depreciation
1	b.	Tranex as of 12/31/98				
2		36501	Transmission Land and Land Rights	10,000	0.0%	-
3		36502	Transmission Rights of Way	227,267	0.0%	-
4		367	Transmission Mains	4,051,497	2.5%	101,287
5		368	Transm Compressor Station Equipmt	519,600	4.5%	14,404
6		369	Transm Meas & Reg Stat Equipmt	145,142	3.0%	4,354
7		371	Telemetering Equipment	60,982	10.0%	6,098
8						
9			Total	5,014,488		126,144

Notes

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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 maintance expenses do not include 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.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

The 1/8th rule is a methodology that has been used by the Commission to calculate cash working capital for as long as we can remember. It is our understanding that the 1/8th ratio represents 1.5 months ÷ 12 months (12.50%) of operation and maintenance expenses. We are unaware of all of the issues that were considered by the Commission in establishing this standard.

WITNESS: Steve Seelye

Notes

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DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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 reponse to AG-17, but showing the balances that are equivalent to the 12/31/98 balance of $220,060

RESPONSE:

a. AG 17 requested the monthly balances for Advances for Construction (A/C 1.252). The amount included in rate base is netted with A/C 1.252.01 Promissory Notes - Extension Deposit Agreements. See attached schedule for the balances in these accounts.

b. See attached.

Sponsoring Witness:

John Brown

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

Item 10
AG Supplemental Request

Line No.	Month/Yr	Advances for Construction A/C 1.252	Promissory Notes - Ext Agmnt A/C 1.252.01	
1	Dec-97	(3,027,045.01)	2,809,470.00	(217,575.01)
2	Jan-98	(3,097,045.01)	2,879,470.00	(217,575.01)
3	Feb-98	(3,097,045.01)	2,879,470.00	(217,575.01)
4	Mar-98	(3,097,045.01)	2,879,470.00	(217,575.01)
5	Apr-98	(3,124,245.01)	2,907,470.00	(216,775.01)
6	May-98	(3,191,445.01)	2,974,670.00	(216,775.01)
7	Jun-98	(2,893,410.01)	2,675,690.00	(217,720.01)
8	Jul-98	(2,948,290.01)	2,730,290.00	(218,000.01)
9	Aug-98	(3,247,750.01)	3,027,090.00	(220,660.01)
10	Sep-98	(3,247,150.01)	3,027,090.00	(220,060.01)
11	Oct-98	(3,247,150.01)	3,027,090.00	(220,060.01)
12	Nov-98	(3,377,350.01)	3,157,290.00	(220,060.01)
13	Dec-98	(3,391,350.01)	3,171,290.00	(220,060.01)
14	Jan-99	(3,573,250.01)	3,357,490.00	(215,760.01)
15	Feb-99	(3,573,250.01)	3,357,490.00	(215,760.01)
16	Mar-99	(3,634,850.01)	3,357,490.00	(277,360.01)
17	Apr-99	(3,664,650.01)	3,357,490.00	(307,160.01)
18	May-99	(3,940,450.01)	3,357,490.00	(582,960.01)
19	Jun-99	(3,960,050.01)	3,357,490.00	(602,560.01)

Notes

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DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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?

RESPONSE:

a. See Attached

b. See Attached

Sponsoring Witness:

John Brown

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

a. Journal Entry Date - 06/30/94

Medical Self Insurance reserve

1.926.04	Medical Coverage	60,000	
1.244.02	Medical - Self Insured		60,000CR

Reserve for medical payments increased to cover claims incurred prior to 6/30/94 and not paid. This brought the reserve account 1.244.02 to the credit balance of $126,000.

Journal Entry Date - 06/30/92

Other Self Insured reserve

1.924	Insurance	25,000	
1.244.06	Other - Self Insured		25,000CR

b. Medical Self Insurance reserve balances are as follows:

6/30/95	126,000CR
6/30/96	126,000CR
6/30/97	126,000CR
6/30/98	126,000CR
6/30/99	126,000CR

Other Self Insured reserve balances are as follows:

6/30/93	25,000CR
6/30/94	25,000CR
6/30/95	25,000CR
6/30/96	25,000CR
6/30/97	25,000CR
6/30/98	25,000CR
6/30/99	25,000CR

Notes

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DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

12. Please provide the rate effective dates of Delta's most recent 5 base rate proceedings (also show case numbers).

RESPONSE:

See the response to AG-2 dated July 2, 1999 and to AG-11 dated June 4, 1999.

Sponsoring Witness:

John F. Hall

Notes

13

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE:

a. The Company pays property taxes on Plant, CWIP and Cushion Gas.

b. Not applicable

c. See attached Schedule

d. Yes, $742,584 is the amount included in the taxes other than income tax.

e. $47,147 is the amount recovered during the test year through the Canada Mountain GCR Recovery mechanism. Therefore, this is the correct amount to exclude.

SPONSORING WITNESS: JOHN BROWN

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 13 (C):

DELTA NATURAL GAS

LINE NUMBER	PLANT ACCOUNT	DESCRIPTION	12/31/98 PLANT BALANCE
1	304	MFG PROD LAND	35,377
2	305	MFG PROD STRUCTR	60,604
3	325	GATH LAND & RGHTS	75,975
4	327	GATH COMP STAT EQP	42,950
5	331	NAT GAS WELL EQUIP	13,392
6	332	GATHERING LINES	1,835,883
7	333	GATH COMP STAT EQP	800,454
8	334	GATH MEAS & REG STAT	82,734
9	35001	STORAGE LAND	14,142
10	35002	STORAGE - ROW	129,425
11	35005	GAS RIGHTS WELLS	46,895
12	35006	GAS RIGHTS STORAGE	171,665
13	351	STOR STRUCT & IMP	69,487
14	352	STORAGE WELLS	226,147
15	35201	STORAGE RIGHTS	860,396
16	35202	STORAGE RESERVOIRS	1,881,731
17	35203	NONREC NAT GAS	294,307
18	353	STORAGE LINES	5,013,487
19	354	STOR COMP STAT	1,134,726
20	355	STOR MEAS & REG	353,185
21	356	PURIFICATION EQUIP	320,225
22	357	STOR OTHER EQUIPMT	47,209
23	36501	TRANS LAND & RIGHTS	43,284
24	36502	TRANS RIGHTS OF WAY	428,208
25	36503	LAND RIGHTS - DEPR	163,626
26	366	TRANS STURCT & IMP	145,444
27	367	TRANSM MAINS	21,011,330
28	368	TRANSM COMP STAT	1,276,289
29	369	TRNASM MEAS & REG	1,078,811
30	371	TRANSM OTHER EQUIP	437,893
31	374	DIST RIGHTS OF WAY	248,478
32	375	DIST STRUCT & IMP	103,373
33	376	DISTRIBUTION MAINS	46,498,998
34	378	DIST REG STAT	965,592
35	379	DIST CITY GATE STAT	390,893
36	380	DIST SERVICES	7,634,653
37	381	DISTRIBUTION METERS	5,454,418
38	382	DIST METER & REG INST	2,365,154
39	383	DIST REGULATORS	2,190,578
40	385	DIST IND METER SETS	1,202,371
41	389	LAND & LAND RIGHTS	845,317

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 13 (C):

DELTA NATURAL GAS

LINE NUMBER	PLANT ACCOUNT	DESCRIPTION	12/31/98 PLANT BALANCE
1	390	STRUCT & IMP	2,882,604
2	391	OFFICE FURN & EQUIP	628,358
3	393	STORES EQUIPMT	42,466
4	394	TOOLS & EQUIP	564,616
5	39401	COMP NAT GAS STAT	421,498
6	395	LABORATORY EQUIP	139,912
7	396	POWER OPERATED EQ	1,524,764
8	397	COMMUNICATION EQU	608,667
9	398	MISC EQUIPMENT	101,995
10	39901	MAPPING COSTS	565,218
11	39902	COMPUTER SOFTWARE	1,559,966
12	39903	COMPUTER HARDWARE	1,824,044
13	TOTAL APPLICABLE TO PROP TAXES		116,859,214
	ACCOUNTS EXCLUDED FROM PROPERTY TAX		
14	301	ORGANIZATION	53,151
15	302	FRAN & CONSENT	1,786
16	392	TRANSPORTN EQUIP	2,844,375
17			2,899,312
18	TOTAL PLANT		119,758,526

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

RESPONSE TO ITEM 13 (c):

CANADA MOUNTAIN

LINE NUMBER	PLANT ACCOUNT	DESCRIPTION	12/31/98 PLANT BALANCE
1	35001	Storage Land	14,142
2	35002	Storage Rights of Way	129,425
3	35005	Gas Rights Wells	1,495
4	351	Structures & Improvements	69,487
5	352	Storage Wells	226,147
6	35201	Storage Rights	860,396
7	35202	Storage Reservoirs	1,881,731
8	35203	Nonrecoverable Natural Gas	294,307
9	353	Storage Lines	5,016,089
10	354	Storge Compr Stat Equipmt	1,134,726
11	355	Storage Meas & Reg Equipmt	353,185
12	356	Purification Equipment	320,225
13	357	Storage Other Equipment	47,209
14	367	Transmission Main	42,858
15			
16	Total Applicable to Property Taxes		10,391,422

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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. Jennings' loan forgiveness compensation included in the pro forma adjusted test year operating expenses? If so, in which accounts are they reflected and where are they reflected on the Company's filing schedules or workpapers?

RESPONSE:

a. There are no Christmas bonus expenses reflected in the 1998 test year operating expenses.

b. The $24,000 of loan forgiveness is recorded in account 1.920.01 for the test year and is an appropriate and allowable expense for the adjusted test year in this rate case. In Delta's Response to PSC 30(c) dated August 11, 1999, this $24,000 was listed. It was inadvertently removed from the test year in error by this adjustment detailed in 30(c). It should not have been and Delta requests that it be included in the final determination of rates in this current rate case. This compensation is supported by evidence in this rate case. See Delta's Response to No. 41 of the AG Data Request dated August 11, 1999, which included an updated compensation study that demonstrates that Delta's compensation (including this loan forgiveness) is low compared to others in this study.

Sponsoring Witness:

John F. Hall

Notes

15

DELTA NATURAL GAS COMPANY, INC
CASE No. 99-176

ATTORNEY GENERAL'S SUPPLEMENTARY REQUEST DATED 09/03/99

QUESTION:

15. With regard to the items listed for "Company Relations Expenses" (totaling $32,496.00) in the response to P.S.C. data request 25b, please explain the purpose and function of the following items:

RESPONSE:

15. Please note the items listed along with an explanation of their purpose and or function.

Delta story history booklets were developed to emphasize Delta's 50th year of operation and to provide information to the public about Delta. They were distributed to various board members, employees, customers and the general public.
All items under vendor #3334 and #3364 for denim shirts, totaling $9,474.00; Lands End advertising for denim shirts – Delta logo: This was associated with shirts distributed to each employee at the annual company meeting. Employees wear these shirts and are thus easily identifiable to customers and the general public.
Door prizes employee meeting: Were distributed to a few employees as a gift at the annual company meeting.
Extra large award jackets, custom caps with embroidery and award knives: Were distributed to employees as a part of Delta's safety awards program to recognize employees who practice and maintain safe work habits over various time frames. This program encourages employees to work safely and maintain a safe work environment. This helps to control costs and reduce lost time due to accidents.
Employee service awards per AT and sample tie tac: Employees receive service awards every 5 years beginning at 5 years of service to recognize their service and contributions to the company and it's customers. This program is meant to assist in recognizing employees and in retaining them and thus reducing costly employee turnover.

WITNESS:

John Hall

Notes

DELTA NATURAL GAS COMPANY
CASE NUMBER 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE:

a. I agree with the amount of $13,580,916 - Canada Mountain Net Plant

Canada Mountain Plant	10,391,422
Canada Mountain CWIP	213,713
Canada Mountain Cushion Gas	3,718,035
Canada Mountain Accum Depr	(742,254)
	13,580,916

b.

Depreciated Net Plant	Delta	Canada Mtn
Plant 1.301 - 1.399.03	119,758,525	10,391,422
CWIP 1.107.01	1,382,759	213,713
Delta Non Utility 1.121	18,592	-
Cushion Gas 1.117	4,046,127	3,718,035
Delta Depr 1.108.01	(33,459,760)	(742,254)
Delta Non Util Depr 1.122	(18,592)	-
	91,727,651	13,580,916

c.

	AG-47 Total Plant
Delta Plant	119,758,525
Delta CWIP	1,382,759
Delta Non Utility	18,592
Cushion Gas	4,046,127
Tranex Plant	4,044,291
Tranex CWIP	38,502
Canada Mountain Depreciation	(742,254)
	128,546,542

SPONSORING WITNESS: JOHN BROWN

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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 represents 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?

RESPONSE:

a. No. $71,630

b & c Section 60301 of Title 49, U S Code authorized the assessment and collection of user fees to fund the pipeline safety program conducted by the U S Department of Transportation. The fee schedule is a pro rata share of total program costs based on the number of miles of transmission pipeline each operator reported at year end of each year.

Sponsoring Witness:

John F. Hall

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

18. With regard to the abnormal sales tax booking in 1998 described in response to AG-26, please provide the following information:

a. Described 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 $17,631 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.

RESPONSE:

a. The $27,631 booking was the actual payment to Kentucky Revenue Cabinet as a result of tax due from the sales tax audit. This is abnormal due to the fact it does not happen yearly.

Detail of accounts for $27,631 payment to Kentucky Revenue Cabinet

Account #	Account Name	Amount
1.236.03	Taxes accrued sales	$ 6,103.69
1.431.02	Interest on ST debt	4,612.48
1.921.06	Misc. Other Items	$16,914.83 *
Total Payment to Kentucky Revenue Cabinet		**$27,631.00**

b. See 18.a. above for breakdown of total payment to the Revenue Cabinet as a result of the sales tax audit. This expense booking is for prior periods. The $16,915 is part of the $27,631 total payment to Revenue Cabinet (see item a. above *).

c. **Booking to Account 1.921.06 relating to sales tax audit:**

Amount paid directly to Revenue Cabinet A/C 1.921.06	$ 16,914.83 (part of $27,631)
Accrual entry to allow for non collection of customers billed Relating to sales tax only	$ 26,352.22
Customers billed sales tax as a result of sales tax audit	$(46,490.97)
Net affect of Sales Tax Audit on Account 1.921.06	**$ (3,223.92)**

WITNESS:

John Brown

Notes

19

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

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 1.921.06 expenses for Tickets for Kings Island, Dollywood, and KY Kingdom.

RESPONSE:

Canada Mountain expenses in account 1.921.06 were $58.08 – Supplies for cookout at Canada Mountain for State Agencies.

Kings Island, Dollywood and KY Kingdom tickets are purchased from amusement parks at a discount for employees to purchase. Delta is reimbursed for the expense, the amount is included in AG-56 Line 402 - Refunds, Reimbursement, Billed to Others.

WITNESS:

John Brown

Notes

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

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?

RESPONSE:

a. Refer to AG-57b Line #140 $59.41 – travel expense for work done at Canada Mountain

b. Expenses were for lodging. Engineering personnel were required overnight stay while working on various work orders in the Pineville area. Lodging in that area is most economical at the State Park.

WITNESS:

John Brown

Notes

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

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.

RESPONSE:

Refer to AG-58 Line 140 - $205.08 attorney to Canada Mountain
Refer to AG-58 Line 184 - $132.93 was for meal at Canada Mountain for State Agencies
Refer to AG-58 Line 210 - $ 14.80 was for meal Edward D. Jones Reps to Canada Mountain

WITNESS:

John Brown

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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".

RESPONSE:

The 1998 expense for 401(k) would have been $161,634 with the elimination of the "reclassification of the Pension expense due to an account distribution correction for a trustee fee for 1997".

Sponsoring Witness:

John Brown

Notes

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

AG DATA REQUEST
Dated 9/4/99

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.

RESPONSE:

The AG has quoted an incorrect amount in this question. Delta's pension expense is recorded in account 1.926.02 Pension. This account for the test year was $292,817.96. The amount referred to in the question (729,269) happens to be expense in account 1.926.04 for the year.

a. The net periodic pension expense per the actuary is $181,167 for the year ended 4/1/1999. This amount is provided in information from the actuary separately from the "actuary report" and is attached.

b. Funding status:

	Excess of assets over obligations
1998	1,892,369
1997	489,893
1996	447,469
1995	92,989
1994	(628,196)

The pension balance is currently prepaid because the required contributions to the plan per IRS rules have exceeded the net periodic pension expense required by the actuary.

WITNESS: John Brown

Delta Natural Gas Company, Inc. Retirement Plan
Statement of Financial Accounting Standards No. 87
For Fiscal Year Ending 4/1/1999

ASSUMPTIONS

	04/01/98	04/01/99
Discount Rate	7.00%	6.50%
Expected Long Term Rate of Return	8.00%	8.00%
Rate of Increase in Compensation	4.00%	4.00%
Average Remaining Future Service	15 Years	15
Measurement Date	04/01/98	04/01/99

FUNDED STATUS	ACTUAL 04/01/98	FOR FISCAL 04/01/98	PROJECTED 04/01/99	ACTUAL 04/01/99
Projected Benefit Obligation	(6,745,269.05)		(7,678,053.48)	(8,286,366.36)
Plan Assets at Fair Value	8,637,638.79		9,962,373.69	9,188,450.03
Funded Status	1,892,369.74		2,284,320.21	902,083.67
Unrecognized Net Obligation or (Asset) Existing at Transition	(169,576.60)		(127,182.46)	(127,182.46)
Unrecognized Prior Service Cost	0.00		0.00	0.00
Unrecognized Net (Gain) or Loss	(869,910.35)		(869,500.59)	612,735.95
(Accrued) or Prepaid Pension Cost	852,882.79		1,287,637.16	1,287,637.16

NET PERIODIC PENSION EXPENSE

Service Cost	467,416.79
Interest Cost	471,938.84
Expected Return on Assets	715,385.10
Amortization of:	
Unrecognized Net Obligation or (Asset) Existing at Transition	(42,394.14)
Unrecognized Prior Service Cost	0.00
Unrecognized Net (Gain) or Loss	(409.76)
Net Pension Expense (Income) at 4/1/1999	181,166.63

RECONCILIATION

(Accrued) / Prepaid Pension Cost at	04/01/98	852,882.79
Net Periodic Pension Expense (Income)		181,166.63
Company Contributions		615,921.00
(Accrued) / Prepaid Pension Cost at	04/01/99	1,287,637.16

Accumulated Benefit Obligation as of 4/1/1999

Vested	5,924,221.18
Non-Vested	33,733.14
Total	5,957,954.32

Notes

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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 AG54b 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.

RESPONSE:

From the information available to Delta, the question asked in AG-54 dated August 11, 1999, could not be answered as the information was in total and for the medical plan year only.

Sponsoring Witness:

John F. Hall

Notes

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

25. Page 16 of 16 of AG-56 shows that the 1998 test year account 1.921.06 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 having 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.

RESPONSE:

25a.	Management Audit	$62,640	
	Rate Case	$24,960	

25b. This is rate case as referred to in question 7 of this data request.

25c. Management Audit completed May 1992. For information about period management audits see KRS 278.255.

25d.i.	Management Audit	$187,858	3 years amortization period
	Rate Case	$125,013	5 years amortization period

25d.ii. As approved by PSC in last order.

25d.iii. See order as referred to in Item 7.

25e. Only unamortized debt expense were included in item AG-23.

WITNESS:

John Brown

Notes

Delta Natural Gas Company, Inc.
Case No. 99-176
AG Data Request

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.

Response:

	Expense Amount
1989	27,157.50
1990	15,087.50
1991	24,140.00
1992	36,210.00
1993	48,280.00
1994	12,070.00
1995	24,140.00
1996	12,070.00
1997	-
1998	12,380.00
1999	-

Witness: John Brown

Notes

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

AG DATA REQUEST
Dated 9/4/99

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?

RESPONSE:

a. I agree, but point out that the 2,112,862 technically is the amount included in cost of gas (balance sheet account) to be recovered via the GCR mechanism. As with all gas costs, the amount is eventually recovered and shows up as gas cost on the income statement, in accordance with the dollar-tracker GCR mechanism. So the precise amount of the $16,260,037 which is attributable to Canada Mountain is likely somewhat different than the $2,112,862, but any difference will be caught up in time.

b. I disagree. The function of the account 922.01 is to remove the various expenses (detailed in AG Item 39 8/11/99) which are attributable to Canada Mountain from the Company's income statement and bill them to Deltran, the operator of the storage field. It really has nothing to do with gas cost. It is classed with Purchased Gas Expense merely for financial statement purposes so as to not distort any single item on the income statement. As stated in a. though, I agree that roughly $2,112,862 of the $16,260,037 are Canada Mountain costs.

c. Delta books

Dr. All accounts listed on AG 39 Response
Cr. Payables/Cash

Dr. Receivable from Deltran
Cr. Canada Mountain Expense Transfer

Deltran books

Dr. Canada Mountain Rental Expense
Cr. Payable to Delta Natural

Dr. Receivable from Delta Natural
Cr. Storage Service Revenue

Delta books

Dr. Gas cost (on balance sheet)
Cr. Payable to Deltran

d. Canada mountain revenue is included in Sales revenue, and also in Purchased gas expense. This self-eliminates. Therefore, if revenues of $38,857,742 are being used in the case, $16,260,037 of gas costs should be used. Both numbers are grossed up for Canada Mountain. Likewise, if $2,112,862 is being removed from purchased gas cost, the same amount needs to be removed from revenues.

WITNESS: John Brown

Notes

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

AG DATA REQUEST
Dated 9/4/99

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.

RESPONSE:

The Company made a conscious effort during the 1999 fiscal year to more aggressively enforce the Company's collection policies. This action reduced bad debt expense for the year and increased collection revenue. Collection revenue for August 1999 was $3,870.

WITNESS: John Brown

Notes

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 contracts 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 we 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 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 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 response to AG-71.

RESPONSE:

(a) The numbers for calendar year 1998 shown in response to AG-71 inadvertently included some firm transportation revenue and volumes. The revenue ($511, 666) and volume ($1,755,567) shown on Walker Exhibit 6 are the correct actual billing numbers.
(b) 2,236,254 represents the Mcf for the fiscal year (12-months ended June 1999). The corresponding revenue is $915,943. The number 2,226,763 was an error due to oversight.
(c) The purpose of the rate switching adjustment, as discussed in Walker testimony, was to give recognition to the fact that certain customers changed rates during the test period. The adjustment merely reflects the difference between the customers' actual revenues during the test period and the revenues for a full year at the rate that the customers' were served under at year-end. One customer was billed under the firm transportation rate for the first five months of 1998 and another for the first seven months (see response to part e). As a result, the 12 months ended June 1999 volumes reflect a full year's deliveries under the special contract rates for one of the two customers and all but 5,032 Mcf for the other. In addition, the June 1999 volumes also contain a full year of deliveries for the special contract customer that initiated service with Delta in May of 1998.
(d) The explanation is set forth on page 5 of Walker Testimony. The calculations are summarized on Walker Exhibit 2, page 1 and the detailed calculations are shown on page 4 of that same exhibit.
(e) Walker Exhibit 6, page 1 also shows the Mcf volume for the special contract customers 1,817,276 that corresponds to the $632,522 in revenue. The average rate

per Mcf delivered can be derived by dividing the revenues by the volume. Since the $632,522 represents the revenues after the pro forma adjustments were made, the corresponding number of customers is five.

(f) Jan98-2, Feb98-2, Mar98-2 Apr98-2, May98-2, Jun98-4 Jul98-4, Aug98-5, Sep98-5, Oct98-5, Nov98-5, Dec98-5, Jan99-5, Feb99-5, Mar99-5, Apr99-5, May99-5, Jun99-5, Jul99-5. The monthly numbers for 1998 only include the number of customers actually billed under special contract rates during the year. The rate switching adjustment shows the months of billings for the two customers that were served under another rate schedule for a portion of the year (One customer through May and the other through July). The year-end adjustment then accounts for the fifth customer which began taking service in June. Therefore, the Adjusted Billings @ Base Rates shown on Walker Exhibit 6 assumes 5 special contract customers for each month of the test-period.

(g) Revised Walker Exhibit 5, column 1 shows the customer-months of billing for the one special contract customer that only used gas for seven months. Column 2 shows the customer-months of billing if that one customer had used for the entire year (12 times the year-end number of 1). Column 3 is the additional customer-months of billing (5) needed to reflect a full-year's usage for that one customer that used gas for five months. Walker Exhibit 5, as filed, in like fashion showed that the customer used gas for 7/12 of the year and the volumes and revenues were adjusted for five additional months of usage. The numbers provided in response to AG-71 represent all the special contract customers. Therefore, the two sets of numbers not comparable.

WITNESS: Part c, d, e, f and g - Randall Walker
Part a and b - John Brown

Notes

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 revenue booked. If the 1998 revenue does 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.

RESPONSE:

(a) A year-end adjustment is to reflect year-end customers over average. It has nothing to do with one year compared to another. As shown on Walker Exhibit 5, the average number of customers served in the test period and the year-end number of customers served were the same. Therefore, no revenue adjustment was necessary to reflect the number of customers served at year-end over the average number served.
(b) The Mcf volume (1,391,510) is also shown on Walker Exhibit 6, page 1. The number of customers (37) are shown on Walker Exhibit 5. Except for a difference of 1 Mcf (likely due to the rounding of the monthly amounts), the volumes correspond as do the number of customers.
(c) Jan98-38, Feb98-38, Mar98-38, Apr98-39, May98-35, Jun98-34, Jul98-37, Aug98-35, Sep98-36, Oct98-38, Nov98-38, Dec98-37, Jan99-32, Feb99-32, Mar99-33,Apr99-35, May99-36, Jun99-35, Jul99-36.
(d) This information is shown in the response to part c, above.
(e) See Attachment.
(f) As shown on Walker Exhibit 5 there is no difference between the average number of customers (37) and the year-end number (37). Therefore, there would be no adjustment.

WITNESS: Parts a, b and f - Randall Walker
Parts c, d and e - John Brown

Delta Natural Gas Company
Case No. 99-176
AG-30 Part (e)

	Interruptible - Rate 20	
	Total	Average
1994 MCF	881,208	
Revenue	1,305,536	
Customer	355	30
1995 MCF	1,004,257	
Revenue	1,463,008	
Customer	384	32
1996 MCF	1,106,659	
Revenue	1,580,346	
Customer	404	34
1997 MCF	1,379,302	
Revenue	1,861,336	
Customer	425	35
1998 MCF	1,391,509	
Revenue	1,931,707	
Customer	445	37
Fiscal Yr 1999 MCF	1,393,293	
Revenue	1,989,848	

Customers Jan-July 1999	
Jan-99	32
Feb-99	32
Mar-99	33
Apr-99	35
May-99	36
Jun-99	35
Jul-99	36
Total	239

Notes

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 revenue booked. If the 1998 revenue does not amount to $1,469,977, please provide a reconciliation.
   (d) Provide a year-end customer revenue adjustment for this rate classes based on the difference in the average 1998 monthly customers and the 12/31/98 level of customers.

RESPONSE:

(a) The Mcf volume (756,019) shown on Walker Exhibit 6, page 1 corresponds (within 1 Mcf) to the volume shown on the response to AG-69. The number of customers (50) shown on Walker Exhibit 5 correspond with the number shown on the response to AG-69. The average rate can be derived by dividing the revenues by either the <u>customers</u> or the volumes.
(b) Jan98-53, Feb98-52, Mar98-52, Apr98-51, May98-50, Jun98-50, Jul98-48, Aug98-49, Sep98-48, Oct98-48, Nov98-49, Dec98-50, Jan99-50, Feb99-50, Mar99-51, Apr99-51, May99-51, Jun99-51, Jul99-50.
(c) See Attachment.
(d) As shown on Walker Exhibit 5 there is no difference between the average number of customers (50) and the year-end number (50). Therefore, there would be no adjustment.

WITNESS: Parts a and d - Randall Walker
Parts b and c - John Brown

Delta Natural Gas Company
Case No. 99-176
AG-31 Part (c)

	Firm - Rate 10 & 15	
	Total	Average
1994 MCF	377,575	
Revenue	740,553	
Customer	476	40
1995 MCF	475,847	
Revenue	942,377	
Customer	515	43
1996 MCF	597,098	
Revenue	1,179,275	
Customer	533	44
1997 MCF	730,389	
Revenue	1,441,620	
Customer	614	51
1998 MCF	756,020	
Revenue	1,469,977	
Customer	605	50
Fiscal Yr 1999 MCF	813,188	
Revenue	166,135	

Customers Jan - July 1999

Jan-99	50
Feb-99	50
Mar-99	51
Apr-99	51
May-99	51
Jun-99	51
Jul-99	50
Total	354

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

32. With regard to the response to AG-76, provide the following additional information:

a. The non-labor operation expenses for Underground Storage (FERC Form2, page 320, line 114)
b. The non-labor operation expenses for Transmission (FERC Form 2, page 323, line 191)
c. The non-labor operation expenses for Distribution (FERC Form 2, page 423, line 216)

RESPONSE:

See attached.

WITNESS:

John Brown

DELTA NATURAL GAS COMPANY, INC.

CASE NUMBER 99-176

12 Mos ended 12/31/98

Line No.	AG Question	FERC A/C No.	FERC Line No.	Line Description	GL #	Description	Total Amount (Adjusted)
1	32.a.	816	103	WELLS EXPENSES	1.816.02	CANADA MOUNTAIN WELLS EXPENSES	2,373
2	32.a.	818	105	COMPRESSOR STATION EXP	1.818.02	CANADA MOUNTAIN COMPRESSOR STATION EXP	9,485
3	32.a.	821	108	PURIFICATION EXP	1.821	CANADA MOUNTAIN PURIFICATION OF NATURAL GAS	1,761
4	32.a.	824	111	OTHER EXPENSES	1.824.02	CANADA MOUNTAIN OTHER UNDERGROUND STORAGE EXP	5,484
5	32.a.	825	112	STORAGE WELL ROYALTIES	1.825	CANADA MOUNTAIN WELL ROYALTIES/RENTS	54,064
6	**32.a.**			**TOTAL**		**NON LABOR RELATED OPERATION EXPENSES FOR UNDERGROUND STORAGE (FERC Form 2, PAGE 320, LINE 114)**	**73,167**
7							
8	32.b.	856	186	MAINS EXPENSES	1.856	RIGHT OF WAY CLEARING	54,869
9							
10	**32.b.**			**TOTAL**		**NON LABOR RELATED OPERATION EXPENSES FOR TRANSMISSION (FERC Form 2, PAGE 323, LINE 191)**	**54,869**
11							
12	32.c.	870	204	OPERATION SUPERVISION & ENGINEERING		P/R & TRANSP	-
13	32.c.	871	205	DISTRIBUTION LOAD DISPATCHING	1.871	TELEMETRY COSTS	35,141
14	32.c.	880	214	OTHER EXPENSES	1.880.01	OPERATIONS OFFICE TELEPHONE	78,673
15	32.c.	880	214	OTHER EXPENSES	1.880.02	OPERATIONS OFFICE UTILITIES	44,599
16	32.c.	880	214	OTHER EXPENSES	1.880.03	OPERATIONS OFFICE MISC	99,132
17	32.c.	880	214	OTHER EXPENSES	1.880.04	FEES TRAINING SCHOOLS	14,173
	32.c.	880	214	OTHER EXPENSES	1.900.03	SMALL TOOLS	53,056
18	32.c.	880	214	OTHER EXPENSES	1.880.04	UNIFORMS	49,153
19	32.c.	880	214	OTHER EXPENSES	1.880.06	WELDING SUPPLIES	7,770
20	32.c.	881	215	RENTS	1.881.01&.02	RENT LAND & LAND RIGHTS	18,174
21	**32.c.**			**TOTAL**		**NON LABOR RELATED OPERATION EXPENSES FOR DISTRIBUTION (FERC Form 2, PAGE 324, LINE 216)**	**399,870**

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE:

See Attached

Sponsoring Witness:

John B. Brown

November Billing Cycle 1 - Residential

Residential	Mcf	Customers
August 1998	30,117	30,987
September 1998	31,261	30,993
	61,378	61,980

Average Monthly Base Load = Mcf / Number of Customers (AMBL = Mcf / Number of Customers)

0.990287189 = 61,378 / 61,980

Number of days in billing cycle

August 1998	28					
September 1998	28					
	56	/	2	=	28	

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (ADBL = AMBL / Average # Days)

0.0353674 = 0.990287189 / 28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)

9103.71023 = 0.0353674 x 28 = 0.9902872 * 9193

Heat Load = Mcf Billed in Cycle - Base Load (HL = Mcf Billed in Cycle - Base Load)

21566.78977 = 30670.5 - 9103.71023

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (HDF = NDD / ADD)

1.229074890 = 279 / 227

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (WNAC = HDF * HL + BL)

35610.90999 = 1.229074890 * 21566.78977 = 26507.19976 + 9103.71023

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf Billed in Cycle (WNAF = WNA / MCF)

1.161080191 = 35610.90999 / 30670.5

November Billing Cycle 1 - Small Commercial

Small Commercial	Mcf		Customers		
August 1998	9,097		3,814		
September 1998	9,444		3,812		
	18,541		7,626	=	2.431287700

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers)**

2.431287700	=	18,541	/	7,626

Number of days in billing cycle					
August 1998	28				
September 1998	28				
	56	/	2	=	28

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (**ADBL = AMBL / Average # Days)**

0.086831704	=	2.431287700	/	28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (**BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)**

2912.68254	=	0.0868317	x	28	=	2.4312876	x	1,198

Heat Load = Mcf Billed in Cycle - Base Load (**HL = Mcf Billed in Cycle - Base Load)**

3778.21746	=	6690.9	-	2912.68254

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (**HDF = NDD / ADD)**

1.229074890	=	279	/	227

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (**WNAC = HDF * HL + BL)**

7556.39475	=	1.229074890	*	3778.21746	=	4643.712209	+	2912.68254

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf in Billing Cycle (**WNAF = WNAC / MCF)**

1.129354011	=	7556.39475	/	6690.9

December Billing Cycle 1 - Residential

Residential	Mcf	Customers
August 1998	30,117	30,987
September 1998	31,261	30,993
	61,378	61,980

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers**)

0.990287189	=	61,378	/	61,980

Number of days in billing cycle

August 1998	28				
September 1998	28				
	56	/	2	=	28

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (**ADBL = AMBL / Average # Days**)

0.0353674	=	0.990287189	/	28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (**BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)**

9446.34960	=	0.0353674	x	28	=	0.9902872	*	9539

Heat Load = Mcf Billed in Cycle - Base Load (**HL = Mcf Billed in Cycle - Base Load)**

57622.25040	=	67068.6	-	9446.3496

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (**HDF = NDD / ADD)**

1.060903733	=	540	/	509

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (**WNAC = HDF * HL + BL)**

70578.01015	=	1.060903733	*	57622.25040	=	61131.66055	+	9446.34960

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf Billed in Cycle (**WNAF = WNA / MCF)**

1.052325681	=	70578.01015	/	67068.6

December Billing Cycle 1 - Small Commercial

Small Commercial	Mcf	Customers		
August 1998	9,097	3,814		
September 1998	9,444	3,812		
	18,541	7,626	=	2.431287700

Average Monthly Base Load = Mcf / Number of Customers (AMBL = Mcf / Number of Customers)

2.431287700	=	18,541	/	7,626

Number of days in billing cycle

August 1998	28				
September 1998	28				
	56	/	2	=	28

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (ADBL = AMBL / Average # Days)

0.086831704 = 2.431287700 / 28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)

3148.51744 = 0.0868317 x 28 = 2.4312876 x 1,295

Heat Load = Mcf Billed in Cycle - Base Load (HL = Mcf Billed in Cycle - Base Load)

13280.98256 = 16429.5 - 3148.51744

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (HDF = NDD / ADD)

1.060903733 = 540 / 509

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (WNAC = HDF * HL + BL)

17238.36142 = 1.060903733 * 13280.98256 = 14089.84398 + 3148.51744

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf in Billing Cycle (WNAF = WNAC / MCF)

1.049232260 = 17238.36142 / 16429.5

January Billing Cycle 1 - Residential

Residential	Mcf	Customers
August 1998	30,117	30,987
September 1998	31,261	30,993
	61,378	61,980

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers)**

0.990287189 = 61,378 / 61,980

Number of days in billing cycle

August 1998	28					
September 1998	28					
	56	/	2	=	28	

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (**ADBL = AMBL / Average # Days)**

0.0353674 = 0.990287189 / 28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (**BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)**

11979.99940 = 0.0353674 x 35 = 1.237859 * 9678

Heat Load = Mcf Billed in Cycle - Base Load (**HL = Mcf Billed in Cycle - Base Load)**

115002.20060 = 126982.2 - 11979.9994

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (**HDF = NDD / ADD)**

1.094713656 = 994 / 908

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (**WNAC = HDF * HL + BL)**

137874.47887 = 1.094713656 * 115002.20060 = 125894.4795 + 11979.99940

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf Billed in Cycle (**WNAF = WNA / MCF)**

1.085777998 = 137874.47887 / 126982.2

January Billing Cycle 1 - Small Commercial

Small Commercial	Mcf	Customers		
August 1998	9,097	3,814		
September 1998	9,444	3,812		
	18,541	7,626	=	2.431287700

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers**)

2.431287700 = 18,541 / 7,626

Number of days in billing cycle

August 1998	28				
September 1998	28				
	56	/	2	=	28

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (**ADBL = AMBL / Average # Days**)

0.086831704 = 2.431287700 / 28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (**BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle**)

4066.32851 = 0.0868317 x 35 = 3.0391095 x 1,338

Heat Load = Mcf Billed in Cycle - Base Load (**HL = Mcf Billed in Cycle - Base Load**)

30789.07149 = 34855.4 - 4066.32851

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (**HDF = NDD / ADD**)

1.094713656 = 994 / 908

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (**WNAC = HDF * HL + BL**)

37771.54553 = 1.094713656 * 30789.07149 = 33705.21702 + 4066.32851

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf in Billing Cycle (**WNAF = WNAC / MCF**)

1.083664096 = 37771.54553 / 34855.4

February Billing Cycle 1 - Residential

Residential	Mcf	Customers
August 1998	30,117	30,987
September 1998	31,261	30,993
	61,378	61,980

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers)**

0.990287189 = 61,378 / 61,980

Number of days in billing cycle

August 1998	28					
September 1998	28					
	56	/	2	=	28	

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle **(ADBL = AMBL / Average # Days)**

0.0353674 = 0.990287189 / 28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle **(BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)**

9583.99952 = 0.0353674 x 28 = 0.9902872 * 9678

Heat Load = Mcf Billed in Cycle - Base Load **(HL = Mcf Billed in Cycle - Base Load)**

89713.60048 = 99297.6 - 9583.99952

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days **(HDF = NDD / ADD)**

1.222366710 = 940 / 769

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load **(WNAC = HDF * HL + BL)**

119246.91818 = 1.222366710 • 89713.60048 = 109662.9187 + 9583.99952

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf Billed in Cycle **(WNAF = WNA / MCF)**

1.200904334 = 119246.91818 / 99297.6

February Billing Cycle 1 - Small Commercial

Small Commercial	Mcf	Customers		
August 1998	9,097	3,814		
September 1998	9,444	3,812		
	18,541	7,626	=	2.431287700

Average Monthly Base Load = Mcf / Number of Customers (**AMBL = Mcf / Number of Customers**)

2.431287700	=	18,541	/	7,626

Number of days in billing cycle

August 1998	28				
September 1998	28				
	56	/	2	=	28

Average Daily Base Load = Average Monthly Base Load / Average # Days in Two Month NonHeat Billing Cycle (**ADBL = AMBL / Average # Days**)

0.086831704	=	2.431287700	/	28

Base Load = Average Daily Base Load * # Days in Billing Cycle * # Customers in Billing Cycle (**BL = ADBL * # DAYS IN Billing Cycle * # Customers in Billing Cycle)**

3277.37568	=	0.0868317	x	28	=	2.4312876	x	1,348

Heat Load = Mcf Billed in Cycle - Base Load (**HL = Mcf Billed in Cycle - Base Load**)

25495.72432	=	28773.1	-	3277.37568

Heating Degree Factor = Normal Degree-Days / Actual Degree-Days (**HDF = NDD / ADD**)

1.222366710	=	940	/	769

Weather Normalization Adjustment Consumption = Heating Degree Factor * Heat Load + Base Load (**WNAC = HDF * HL + BL**)

34442.50034	=	1.222366710	*	25495.72432	=	31165.12466	+	3277.37568

Weather Normalization Adjustment Factor = Weather Normalization Adjustment Consumption / Mcf in Billing Cycle (**WNAF = WNAC / MCF**)

1.197038218	=	34442.50034	/	28773.1

Delta Natural Gas Company, Inc.
Case No. 99-176
Attorney General's Supplemental Request Dated 9/3/99

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.

RESPONSE:

As was stated in response to No. 94 of the first AG data request, system extensions are considered in the context of Delta's policy of up to 200 feet per customer. If projects fall within this criteria, there is no requirement for further specific management approval. Due to Delta's smaller size and rather lean, informal structure, projects are routinely reviewed/discussed by various management of the Company. There is no established form or method of presentation, but there is an effective involvement by management as necessary. It is rather unstructured and depends on the individual circumstances of each extension. Consideration is given to the customer potential, timing needs, footage, future development possibilities and any larger customer loads such as schools.

The attached listing reflects data for several of Delta's larger extensions from a footage standpoint. It was not clear in the request what "largest" meant. This was not necessarily presented to management in this form, as it is done on a case-by-case basis, as explained above.

WITNESS: Glenn R. Jennings

System	Start Date	Project Name	Footage	Residential Customers Expected	Extension Notes
Berea	7/23/98	Barnes Mill Road	20,123'	120	new development with available lots
Manchester	8/14/97	Anneville	16,446'	75	Annville Institute (Large Customer)
Berea	9/18/96	Hwy 21, Indian Hills	13,321'	82	new development with available lots
Nicholasville	10/10/96	South Point	21,801'	498	
Stanton	10/13/97	Hwy 52	18,795'	101	
London	4/17/96	Autumn Ridge	17,910'	87	new development with available lots
London	7/26/96	Hwy 80 East	23,654'	81	new development and large school
Barbourville	9/16/96	Trace Branch	14,715'	80	
Berea	6/20/96	Bush Bottom	12,354'	91	new development with available lots
Corbin	3/12/97	Blossom Ridge	4,502'	44	
Nicholasville	9/12/96	Southbrook	4,406'	66	
Stanton	1/20/97	Airport Road	3,966'	36	
London	4/1/96	Laurel Trace	5,900'	52	
Stanton	7/17/96	Graham Circle	9,167'	58	
Corbin	7/21/97	Bramblewood	10,433'	60	
Berea	4/1/98	Bayview	6,618'	84	
Corbin	4/21/98	Keavy Hwy 312	7,559'	23	large school and conversion customers
Berea	4/14/98	Speedwell	6,929'	83	
Nicholasville	8/27/98	Village Parkway	9,797'	149	

35. Reference AG data request no. 98.

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 regultory commission orders that Mr. Seelye is aware that approves or authorizes the weighting scheme proposed by Mr. Seelye in this case.

RESPONSE:

a. A standard weighted least squares technique was utilized in the zero intercept analysis for Delta. Our analysis used Microsoft EXCEL97 to perform a multivariate regression using the model described in the direct testimony of Steve Seelye. (See also our response to item 36 of the AG's data request.) We also used the standard weighted least squares (WLS) regression program in SPSS to check the results of our model. <u>SPSS's WLS program produces exactly the same intercept as our model.</u>

Weighted least squares is a commonly used regression technique and there is a great deal of literature written on the subject. Many statistical packages such as SAS and SPSS have the capability to perform weighted least squares, and these packages also include documentation on the subject. The reference cited in our response to AG request no. 98 was simply one of many such texts. The referenced text can be reviewed at the University of Kentucky Library. Attached is the catalogue information from the University of Kentucky. Chapter 5 is titled "Weighted Least Squares."

b. The National Association of Regulatory Commissioners (NARUC) *Electric Utility Cost Allocation Manual* (January, 1992) prescribes the use of a weighting "scheme" for purposes of performing the zero intercept methodology. The following are NARUC's instructions for Account 365 – Overhead Conductors and Devices (the instructions are the same for underground conductors, tranformers, and poles):

- Determine <u>**the feet**</u>, investment, and average installed book cost per foot for distribution conductors by size and type.

- Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor <u>**weighted by feet or investment**</u> in each category, and developing a cost for the utility's minimum size conductor.

Although this is a description of the methodology for electric overhead conductor, the principle is exactly the same for gas mains. In other words, the phrase "gas mains" can be substituted for "overhead conductors" in the above language from NARUC's *Electric Utility Cost Allocation Manual.*

c. We have not performed a search of Commission orders in other jurisdictions. However, we are aware that in Kentucky, Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) have utilized the weighting "scheme" proposed by Mr. Seelye. The Commission has accepted this weighting "scheme" on a number of occasions. Based on discussions with other utilities, participation in EEI and AGA rate committee meetings, and attending NARUC cost of service meetings, we believe that weighted least squares represents the "standard" approach for performing a zero intercept analysis.

WITNESS: Steve Seelye

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Record Display from University of Kentucky Catalog
Record **10** of **27** for Search: **au=("Chatterjee, S")**

Mark

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Title	Regression analysis by example /
Author	Chatterjee, Samprit, 1938-
Publisher	New York : Wiley,
Date	c1977.
Description	xiv, 228 p. : ill. ; 24 cm.
Series	Wiley series in probability and mathematical statistics
Notes	Includes bibliographies and index.
Database Number	ABG8843
ISBN	0471015210
Subjects	Regression analysis.
Other Authors	Price, Bertram, 1939- joint author.
Holdings	*Location:* Math Sciences Library *Call No:* QA278.2 .C5 1977

Previous Next

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.

RESPONSE:

The theory behind weighted regression is that if prices are calculated by taking the average over various quantities within a category, then the quantity in each category should be taken into consideration in the regression analysis. The need to use weighted regression, rather than unweighted regression, can be seen by examining the feet of pipe for each category of distribution mains on Delta's system:

Feet	Unit Cost	Pipe Size
442,766	5.03896	1.50
3,625,826	5.01638	2.00
56,307	2.38983	3.00
1,077,977	9.20162	4.00
51,168	8.27142	6.00
108,137	1.44549	1.50
429,630	1.32747	2.00
73,925	1.28091	3.00
259,512	5.38478	4.00
273,679	5.72755	6.00
79,984	6.43705	8.00

The first five items in the table represent plastic pipe, and the second six represent steel pipe. As can be see from this table, Delta has 3,625,826 feet of 2" plastic pipe, but only 51,168 feet of 6" plastic pipe. Therefore, there are 71 times more 2" plastic mains than there are 6" plastic mains. A weighted regression analysis would weight the average price of each category of pipe by the number of items (i.e., the number of feet) in each category. In other words, a weighted regression analysis would account for the fact that there is much more 2" plastic pipe than there is 6" plastic pipe. If each size of pipe is not weighted then the analysis will treat 6" pipe the same as 2" pipe even though only a small amount of 6" pipe has been installed. Weighting is therefore necessary to give a better representation of the system.

Weighted regression is a standard approach when average data, rather than individual data points, are utilized in a regression analysis *and* when the number of items used to calculate the averages vary by category. If the same quantity of pipe was installed for each category of pipe it would not be necessary to perform a weighted regression. But since the quantity of pipe varies dramatically by category of mains, then it is absolutely essential that a weighted regression analysis be performed. It should also be pointed out that performing a weighted regression analysis is consistent with the methodology prescribed by the National Association of Regulatory Commissioners' (NARUC's) *Electric Utility Cost Allocation Manual* (January, 1992) for overhead conductor, underground conductor, transformers, and poles.

The need to perform a weighted regression analysis is analogous to the need to use weighting if we were going to calculate the overall average cost of pipe on Delta's system based on the figures shown in the above table. Simply taking a simple average of each of the eleven unit costs shown in the above table would not provide a reasonable and accurate estimate of the average cost of mains on Delta's system. Obviously, what would need to be done is to calculate an average by *weighting* the unit costs by the feet of pipe in each category. Otherwise, the category of mains with a small number of feet installed would have the same impact on the average as those categories with over 1 million feet of installed pipe. A weighted regression analysis is also analogous to calculating a weighted cost of capital for determining a utility's overall rate of return. Since the utility's capital structure is generally not financed with an equal percentage of debt and equity, it is necessary to calculate a *weighted* cost of capital. Analogies such as these could be provided *ad nauseam*.

The underlying mathematical theory behind weighted regression is that the error term in the regression model should be weighted by the number of items in each category. Therefore, our objective is to minimize the weighted sum of squared residuals (S) of the standard linear model ($\hat{Y} = \beta_0 + \beta_1 X$):

$$S = \sum_{i=1}^{k} n_i \left(Y_i - \beta_0 - \beta_1 X_i \right)^2 \qquad \text{Equation 1.0}$$

where, n_i is the quantity (feet) of each type of main, Y_i is the price of each type of main, X_i is the size of each type of main, β_0 is the zero-intercept, and β_1 is the slope of the linear model. What is being accomplished here is that the squared residual term is being weighted by the feet of mains n_i for each category of pipe. In other words, we are weighting the error term for each type and size of pipe.

Our goal is to determine the values of β_0 and β_1 that minimize S. This is done by taking the first partial derivatives of S with respect to β_0 and β_1 and setting them equal to zero, as follows:

$$\frac{\partial S}{\partial \beta_0} = \sum_{i=1}^{k} -2n_i \left(Y_i - \beta_0 - \beta_1 X_i \right) = 0 \qquad \text{Equation 2.1}$$

$$\frac{\partial S}{\partial \beta_1} = \sum_{i=1}^{k} -2n_i X_i \left(Y_i - \beta_0 - \beta_1 X_i \right) = 0 \qquad \text{Equation 2.2}$$

This system of equations is identical to the system of equations obtained by taking the first partial derivatives of the sum of squared residuals (S) of the following linear model:

$$\sqrt{n_i}\hat{Y}_i = \beta_0\sqrt{n_i} + \beta_1\sqrt{n_i}X_i \qquad \text{Equation 3.0}$$

which is the weighted model used in the our zero-intercept analysis. The sum of squared residuals (S) of this model is:

$$S = \sum_{i=1}^{k} \left(\sqrt{n_i}Y_i - \sqrt{n_i}\beta_0 - \sqrt{n_i}\beta_1 X_i\right)^2 \qquad \text{Equation 4.0}$$

Taking the first partial derivatives of S with respect to β_0 and β_1 and setting them equal to zero yields the following system of equations:

$$\frac{\partial S}{\partial \beta_0} = \sum_{i=1}^{k} -2\sqrt{n_i}\left(\sqrt{n_i}Y_i - \beta_0\sqrt{n_i} - \beta_1\sqrt{n_i}X_i\right) = 0 \qquad \text{Equation 5.1}$$

$$\frac{\partial S}{\partial \beta_1} = \sum_{i=1}^{k} -2\sqrt{n_i}X_i\left(\sqrt{n_i}Y_i - \beta_0\sqrt{n_i} - \beta_1\sqrt{n_i}X_i\right) = 0 \qquad \text{Equation 5.2}$$

Of course, this system of equations reduces to the same system of equations shown in Equation 2.1 and 2.3.

Therefore, we can run a standard multivariate regression package (such as the regression routine included in Microsoft Excel97) using the model shown in Equation 3.0 in order to determine the parameter estimates for Equation 1.0. However, it should be noted that the multivariate regression package must be executed with the intercept feature switched off because the zero intercept term β_0 in Equation 3.0 is associated with the variate $\sqrt{n_i}$.

WITNESS: Steve Seelye

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.

Response:

a. The pipeline interconnections on the map submitted in response to AG data request no. 98 are the points identified as "Purchase Station". Attached is another map showing, by the blue dots, each pipeline interconnection. Delta does not own or operate any LNG or other peak shaving facilities.

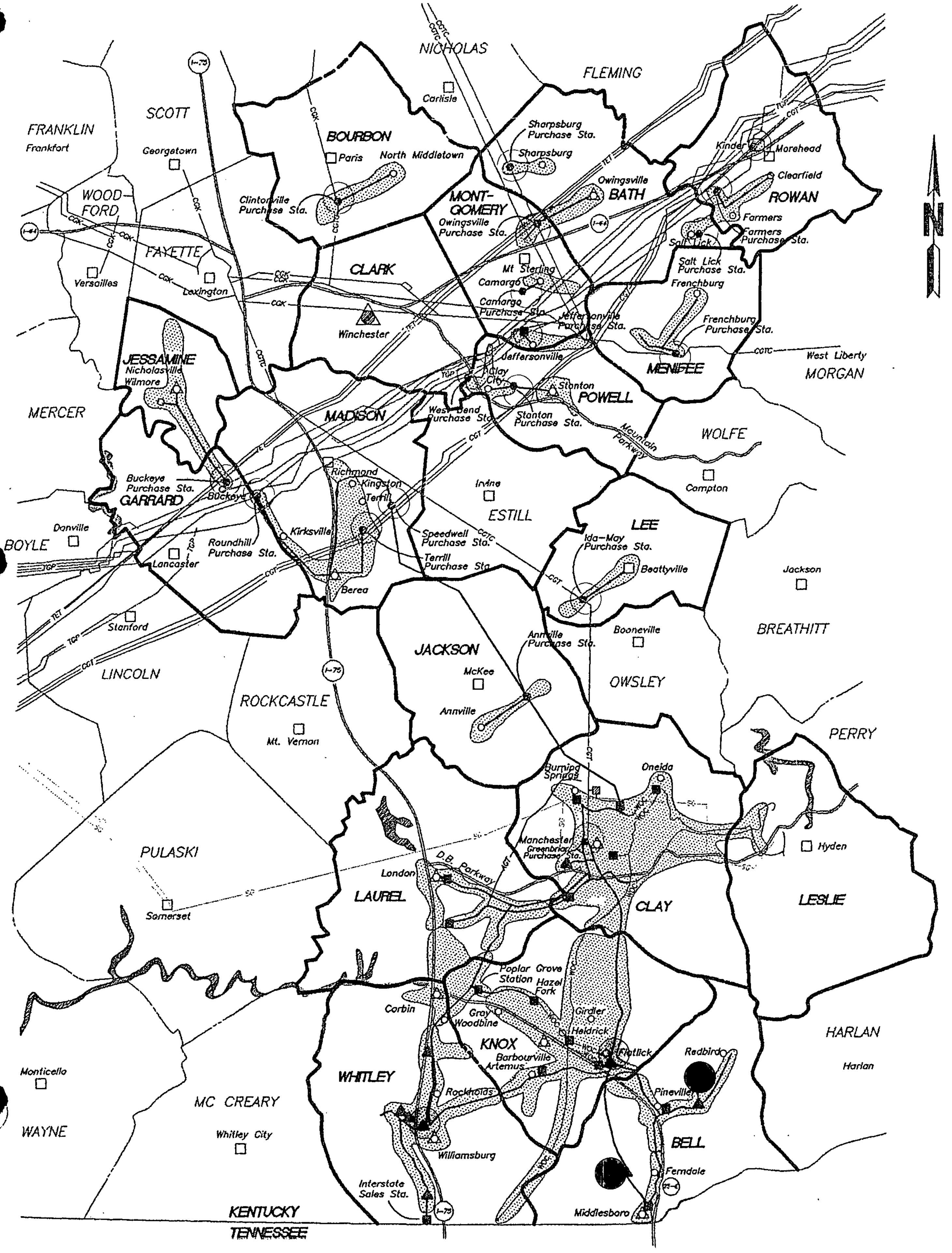
b. Attached is a key to the map provided in response to AG-98.

c. On-system storage fields are indicated by red dots on the attached map.

d. Delta's Williamsburg compressor and Flat Lick Ajax compressor are in-line units used to sustain delivery system pressures and are identified on the attached map by green dots.

Witness: Glenn Jennings

DELTA NATURAL GAS COMPANY INC.
SERVICE AREA



DELTA NATURAL GAS COMPANY INC.
SERVICE AREA

LEGEND

	DELTA NATURAL GAS TRANSMISSION LINE
WOC	WISER OIL COMPANY
AGT	ATLANTIC GAS TRANSMISSION
CGTC	COLUMBIA GAS TRANSMISSION CORPORATION
TGP	TENNESSEE GAS PIPELINE COMPANY
TET	TEXAS EASTERN TRANSMISSION
CGT	COLUMBIA GULF TRANSMISSION COMPANY
SG	SOMERSET GAS COPMANY
CGK	COLUMBIA GAS OF KENTUCKY
HCG	HOLLY CREEK GAS COMPANY
	COMPRESSOR STATION
	METERING STATION
	PURCHASE STATION
	COUNTY LINE
	CORPORATE OFFICE
	BRANCH OFFICE
	COMMUNITY SERVED BY DELTA NATURAL GAS
	DELTA DISTRIBUTION SERVICE AREA (APPROX.)

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 make 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 "base loads and temperature-sensitive loads" [Seelye Testimony, pages 8-9] to arrive at the DEM03 demands.

RESPONSE:

a. Two of the five special contract customers are served directly off of transmission lines on Delta's system; therefore Delta's gas distribution system is not utilized to provide service to these two customers. Consequently, the demands for these customers are not included in the allocation of distribution plant (DEM04). The two special contracts have an annual volume of 1,450,309 Mcf and a design day requirement of 3,973 Mcf.

b. Delta's distribution facilities are not utilized to deliver off-system transportation. The gas is delivered into Delta's transmission system and is transported to the customer across the transmission system.

c. See Seelye Exhibit 3. Also, see response to item (a), above.

WITNESS: Steve Seelye

39. Reference AG data request no. 100. For DEM01 and DEM03-05, please provide the absolute amount of interruptible load included in each factor.

RESPONSE:

Customer Class	DEM01	DEM03	DEM04	DEM05
Residential (GS)	0	0	0	0
Small Commercial (GS)	0	0	0	0
Large Commercial and Industrial (GS)	0	0	0	0
Interruptible	4,283	4,283	4,283	4,283
Special Contracts	4,979	4,979	1,006	1,006
Off-System Transportation	3,847	3,847	0	0

WITNESS: Steve Seelye

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

40. Reference AG data request no. 102. Please provide any interruptible load included in the estimated peak day requirements shown for each year.

RESPONSE:

1996-1997 Estimated Peak Day Requirements:

Class 200 Commercial - Interruptible	26 Mcf
Class 300 Industrial - Interruptible	453
Class 500,600,800 Transportation - Interruptible	3,020
Total	3,499

1997-1998 Estimated Peak Day Requirements:

Class 200 Commercial - Interruptible	29 Mcf
Class 300 Industrial - Interruptible	458
Class 500,600,800 Transportation - Interruptible	2,927
Total	3,414

1998-1999 Estimated Peak Day Requirements:

Class 200 Commercial - Interruptible	32 Mcf
Class 300 Industrial - Interruptible	462
Class 500,600,800 Transportation - Interruptible	2,643
Total	3,137

Sponsoring Witness:

Glenn R. Jennings

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

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.

Response:

See Response to 42 b. Delta has only one interruptible customer whose usage can be determined on a daily basis. That interruptible customer's daily nominations and daily usages on the peak days are as follows:

Date	Nomination	Actual Usage
January 4, 1999	2200 Mcf	2832 Mcf
March 11, 1998	2200 "	2663 "
January 17, 1997	2214 "	2043 "

Delta has only one firm transportation customer whose usage can be determined on a daily basis. That customer has only been on service for one peak day period – January 4, 1999. Their nomination on January 4, 1999 was 2912 Mcf, and their usage on that date was 2958 Mcf.

Witness: Glenn Jennings

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

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.

RESPONSE:

1996-1997 Estimated Peak Day Requirements:
Class 500,600,800 Transportation -

Firm	7,046 Mcf
Interruptible	3,020
Total	10,066

1997-1998 Estimated Peak Day Requirements:
Class 500,600,800 Transportation -

Firm	8,781 Mcf
Interruptible	2,927
Total	11,708

1998-1999 Estimated Peak Day Requirements:
Class 500,600,800 Transportation -

Firm	10,573 Mcf
Interruptible	2,643
Total	13,216

Sponsoring Witness:

Glenn R. Jennings

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

42.

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.

Response:

Delta has only one transportation customer whose actual daily usage is routinely recorded and was recorded for each of the three sendout periods. That customer is interruptible, and the actual usage for the three peak day periods was:

January 4, 1999 - 2832 Mcf
March 11, 1998 - 2663 Mcf
January 17, 1997 - 2043 Mcf

Delta has one firm transportation customer whose actual daily usage was recorded for the January 4, 1999 gas day, and that customer's usage was 2958 Mcf.

Witness: Glenn Jennings

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

AG DATA REQUEST
Dated 9/4/99

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.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

The Company owns two storage fields: Canada Mountain and Kettle Island. As discussed in Response 27 and related responses in other requests, all quantifiable costs related to Canada Mountain are recovered in gas cost rates.

Kettle Island costs are recovered in base rates. Gas that is withdrawn from Kettle Island is charged to purchased gas and flows through the Company's GCR just like outside purchases.

WITNESS: John Brown

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

AG DATA REQUEST
Dated 9/4/99

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.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

As discussed in response 43, Kettle Island is the only company-owned storage facility which has costs included in test year cost of service.

Current net book value of Kettle Island assets is $76,569, of which $45,400 is not depreciable. There is $265,579 in storage gas at Kettle Island and $328,092 in cushion gas.

O&M expenses are recorded in accounts that also include the Company's gathering operations, so Kettle Island O&M expenses are not specifically identified.

WITNESS: John Brown

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

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.

RESPONSE:

Please refer to Response to item 52 of this request for GCR year contract storage costs which costs are included in costs at issue in this proceeding.

WITNESS:

Glenn Jennings

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

46.

Please list and explain each and every benefit that Delta gets from its storage services that justifies the costs of the storage services.

Response:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

The primary benefit derived from storage services is security of supply for Delta's firm customers. Assuming the historical pricing differences between winter prices and summer prices, storage services can also provide the opportunities for cost savings by injecting less costly gas during the non-heating months, which gas can be withdrawn during times when prices and demand are higher.

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 pipelines supplying gas to Delta for these systems. Without storage, Delta could not supply the requirements of its firm customers.

The storage services under contract with Delta's interstate suppliers (Columbia Gas Transmission and Tennessee Gas Pipeline) are necessary to supplement the pipeline flowing capacities of these interstate transporters. For example, Delta was allocated, during the implementation of FERC Order 636, only one-third of its Columbia Maximum Day Contract Quantity as firm transportation capacity on Columbia Gulf Transmission Corporation. Therefore, the contracted Columbia storage service, which is an imbedded component of the Columbia GTS contracts, is necessary to meet the remaining two-thirds of the firm requirements in Delta's Columbia supplied systems.

Witness: Glenn Jennings

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.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

Only a small percentage of customers are served from pipe classified as transmisison pipe. Delta has not conducted an analysis which would allow it to provide the information requested.

WITNESS: Steve Seelye

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 OS customer peak demands.

d. Please provide the SP1 and OS test year demand coincident with system peak.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

a. & b. The methodology for calculating design day requirements was based on an estimate of base load plus temperature sensitive load at a zero degree design day. This methodology assumes that the base load for each customer class, including residential, small commercial, large commercial and industrial, interruptible, special contracts and off-system transportation, is delivered at constant usage. Therefore, the base loads for Special Contracts and Off-System Transportation customers were determined in the same manner as the other customer classes, including Residential. Our experience indicates that this is not an unreasonable assumption. In general, it is a customer's temperature sensitive load that causes its gas usage to vacillate.

c. The information requested is not available.

d. The information requested is not available.

WITNESS: Steve Seelye

49. Please explain how the Delta system is used that makes it reasonable for OS. Customer 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).

RESPONSE:

See response to item 38(b).

WITNESS: Steve Seelye

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

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:

Response:

Delta maintains the listed capacity resources to meet its design peak day requirements. However, the "Total Capacity Resources" of "80,367 Dth" as shown in AG 50 of the AG's Supplemental Request for Information is not available at the interconnection with the interstate pipelines to meet Delta's design peak day requirements. To clarify, Delta maintains FS-MA (Firm Storage – Market Area) firm withdrawal capability on Tennessee Gas Pipeline of 8,363 Dth, but those storage withdrawals must flow to Delta's interstate pipeline interconnection under either the FT-A or FT-G firm transportation capacity. Therefore, the FS-MA firm withdrawal volumes cannot be <u>added</u> to the pipeline firm transportation capacities. The total volumes flowing to Delta on a peak day will consist of a percentage of the gas from storage withdrawals and the remainder from flowing production gas.

Likewise, the Columbia GTS Storage volume of 10,216 Dth is imbedded in the "Columbia/Gulf GTS Firm Transportation" volume of 12,070 Dth and should not be added to the firm pipeline transportation capacity when determining the peak day contracted deliverability to Delta's interstate pipeline interconnections. The total on-system storage deliverability and the firm transportation on the interstate pipelines equals approximately 60,000 Dth.

Witness: Steve Seelye

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

51.

Identify and explain any differences in the Company's current capacity resources and those identified above.

Response:

See Response to No. 50.

Witness: Steve Seelye

52

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

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.

Response:

Attached are copies of Schedule II and Schedule XI from Delta's Gas Cost Recovery filing of June 28, 1999 (Case No. 97-066-G). These schedules reflect the billing determinants and rates for the interstate pipeline transportation and storage services and for Canada Mountain storage services.

Witness: Glenn Jennings

TENNESSEE GAS PIPELINE RATES EFFECTIVE 8/01/99

		DTH VOLUMES	FIXED OR VARIABLE		RATES	ANNUAL COST
FT-G RESERVATION RATE - ZONE 0-2	1.	18,482	F	2.	$9.552	$176,540
FT-G RESERVATION RATE - ZONE 1-2	3.	90,043	F	4.	$8.072	$726,827
FT-G COMMODITY RATE - ZONE 0-2	5.	116,603	V	6.	$0.0902	$10,518
FT-G COMMODITY RATE - ZONE 1-2	7.	568,086	V	8.	$0.0798	$45,333
FT-A RESERVATION RATE - ZONE 0-2	9.	2,820	F	10.	$9.552	$26,937
FT-A RESERVATION RATE - ZONE 1-2	11.	12,096	F	12.	$8.072	$97,639
FT-A RESERVATION RATE - ZONE 3-2	13.	1,884	F	14.	$4.692	$8,840
FT-A COMMODITY RATE - ZONE 0-2	15.	85,775	V	16.	$0.0902	$7,737
FT-A COMMODITY RATE - ZONE 1-2	17.	367,920	V	18.	$0.0798	$29,360
FT-A COMMODITY RATE - ZONE 3-2	19.	57,305	V	20.	$0.0552	$3,163
FUEL & RETENTION - ZONE 0-2	21.	202,378	V	22.	$0.1256	$25,417
FUEL & RETENTION - ZONE 1-2	23.	936,006	V	24.	$0.1044	$97,733
FUEL & RETENTION - ZONE 3-2	25.	57,305	V	26.	$0.0311	$1,782
SUB-TOTAL						$1,257,825
FS-PA DELIVERABILITY RATE	27.	18,288	F	28.	$2.02	$36,942
FS-PA INJECTION RATE	29.	186,757	V	30.	$0.0053	$990
FS-PA WITHDRAWAL RATE	31.	186,757	V	32.	$0.0053	$990
FS-PA SPACE RATE	33.	2,241,084	F	34.	$0.0248	$55,579
FS-PA RETENTION	35.	186,757	V	36.	$0.0395	$7,386
SUB-TOTAL						$101,886
FS-MA DELIVERABILITY RATE	37.	103,632	F	38.	$1.17	$121,249
FS-MA INJECTION RATE	39.	387,622	V	40.	$0.0102	$3,954
FS-MA WITHDRAWAL RATE	41.	387,622	V	42.	$0.0102	$3,954
FS-MA SPACE RATE	43.	4,651,464	F	44.	$0.0187	$86,982
FS-MA RETENTION	45.	387,622	V	46.	$0.0395	$15,329
SUB-TOTAL						$231,468
TOTAL TENNESSEE GAS PIPELINE CHARGES						**$1,591,179**

COLUMBIA GAS TRANSMISSION RATES EFFECTIVE 8/01/99

GTS COMMODITY RATE	47.	653,401	V	48.	$0.8051	$526,053
FUEL & RETENTION	49.	653,401	V	50.	$0.1332	$87,010
TOTAL COLUMBIA GAS TRANSMISSION CHARGES						**$613,063**

COLUMBIA GULF CORPORATION RATES EFFECTIVE 8/01/99

FTS-1 RESERVATION RATE	51.	50,496	F	52.	$3.1450	$158,810
FTS-1 COMMODITY RATE	53.	653,401	V	54.	$0.0192	$12,545
FUEL & RETENTION	55.	653,401	V	56.	$0.0004	$265
TOTAL COLUMBIA GULF CORPORATION CHARGES						**$171,621**

TOTAL PIPELINE CHARGES **$2,375,863**

DELTRAN, INC.

SCHEDULE XI

QUARTERLY CALCULATION OF RESERVATION CHARGE
PAYABLE BY DELTA NATURAL GAS CO., INC.

Deltran Operation and Maintenance Expenses
(Period Ended April 30, 1999)

Lease Charge (Schedule XII)	2,370,318
Other operation and maintenance expenses	-
Total Gas Storage Charges	2,370,318
Monthly Reservation Charge	197,526

DELTA NATURALGAS COMPANY, INC.
RESPONSE TO SUPPLEMENTAL REQUEST FOR INFORMATION
BY THE ATTORNEY GENERAL
CASE NO. 99-176

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).

Response:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

Delta has no balancing charge or tariff. Delta's on and off system transportation tariffs determine transportation charges.

Witness: Glenn Jennings

54. Reference the Company's cost of service study. Please provide a detail a detailed explanation.

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

a. Tranex Plant 367-371, Tranex Acquisition Adjustment, and Circle R are plant costs (and credits) related to the purchase of utility transmission plant that connects the southern portion of Delta's system with Columbia Gulf Transmission and is used to supply natural gas service to customers in the region. It is also used as a primary transmission source for injections into storage facilities during the summer injection season. Without these facilities Delta would not have the capacity to meet its firm peak day requirements, especially in light of declining local gas production.

We could not find Canada Mountain referenced on Exhibit 1-5.

b. The referenced items on Exhibit 1-9 relate to accumulated depreciation. For Tranex PT365 and PT389 see the response to item (a), above. Canada Mountain relates to plant that has been removed from ratebase and which is not recovered through base rates.

c. See the response to item (b), above.

WITNESS: Steve Seelye

55. Reference the Company's cost of service study, Exhibit 2-29. Please identify the source of the allocation vector OMTT.

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

The functional vector OMTT refers to total operation and maintenance expenses.

WITNESS: Steve Seelye

DELTA NATURAL GAS COMPANY, INC.
CASE NUMBER 99-176
12 Mos ended 12/31/98

56. Please provide a schedule showing actual monthly deliveries on behalf of transportation customers and actual usage for the period November 1995 to present.

RESPONSE:

See Attachments.

WITNESS:

John Brown

Delta Natural Gas Company
Case No. 99-176
AG-56

Transportation Customers Actual Monthly Deliveries November 1995-June 1999

	1995	1996	1997	1998	1999
January		255,589	288,450	299,582	396,495
February		224,332	250,759	278,463	368,496
March		226,095	243,251	293,035	405,922
April		264,957	289,081	270,275	346,204
May		202,558	218,262	237,756	329,326
June		196,825	221,601	251,035	342,831
July		208,889	253,843	376,692	
August		202,197	322,757	367,281	
September		192,730	261,565	360,007	
October		266,680	335,394	399,084	
November	218,632	257,115	267,468	422,541	
December	231,455	257,561	335,090	404,430	

Delta Natural Gas Company
Case No. 99-176
AG-56

Transportation Customers Actual Monthly Usage November 1995-June 1999

	1995	1996	1997	1998	1999
January		278,074	270,512	301,492	388,858
February		223,669	194,825	277,138	364,982
March		202,175	337,640	297,035	436,296
April		262,540	267,190	270,663	339,012
May		192,136	224,835	233,493	313,524
June		186,220	198,803	286,981	355,352
July		214,433	283,341	346,825	
August		180,730	347,196	349,843	
September		258,409	259,590	335,509	
October		203,934	295,613	382,614	
November	220,581	257,296	282,822	415,271	
December	225,627	249,278	331,680	406,232	

DELTA NATURAL GAS COMPANY, INC.
CASE NO. 99-176
ATTORNEY GENERAL'S SUPPLEMENTAL REQUEST FOR INFORMATION

57. Reference the response to AG 102. Please identify actual deliveries to Delta on behalf of third-party transportation on peak day for the 1996-97, 1997-98 and 1998-99 winter seasons.

RESPONSE:

The actual deliveries that could be identified are as follows:

1996-97:	2,486 Mcf
	746 Interruptible
	1,740 Firm
1997-98:	8,510 Mcf
	2,127 Interruptible
	6,383 Firm
1998-99:	9,031 Mcf
	1,806 Interruptible
	7,225 Firm

Sponsoring Witness:

Glenn R. Jennings

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)

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

The regression analysis was performed using the LINEST function in Microsoft Excel97; however, the results were verified using the standard weighted least squares (WLS) model in SPSS 7.5. With the exception of the attached sheet (showing the LINEST Array) all output from Excel97 was included in the cost of service study.

WITNESS: Steve Seelye

Delta Natural Gas Company, Inc.

Zero Intercept Analysis
Account 376 -- Distribution Mains

December 31, 1998

LINEST Array

0.859843974	3.141088385
0.444726482	1.317330508
0.828621645	1463.48052
21.75769162	9
93200170.1	19275977.1

59

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?

RESPONSE:

On advice from counsel, Delta objects to this question on grounds that it is not a proper follow-up to previous requests for information. Without waiving its objection, Delta provides the following response.

No. ***Unweighted*** regression is ***not appropriate*** for use in performing a zero intercept analysis because it would give the same weight in the analysis for main sizes which the company has only installed a few feet as it would for main sizes which the company has installed miles of pipe. The following table shows the number of feet, the unit cost and the pipe size for each type of pipe on Delta's system:

Feet	Unit Cost	Pipe Size
442,766	5.03896	1.50
3,625,826	5.01638	2.00
56,307	2.38983	3.00
1,077,977	9.20162	4.00
51,168	8.27142	6.00
108,137	1.44549	1.50
429,630	1.32747	2.00
73,925	1.28091	3.00
259,512	5.38478	4.00
273,679	5.72755	6.00
79,984	6.43705	8.00

The first five categories of pipe are plastic and the last six are steel. As can be seen from this table, Delta has 3,625,826 feet of 2 inch plastic pipe, which is the largest quantity of any size of pipe installed on Delta's system. However, Delta has 51,168 feet of 6 inch plastic pipe. An unweighted regression analysis would give the same weight to the 51,168 feet of 6 inch pipe as it would to the 3,625,826 feet of 2 inch pipe even though there is approximately is approximately 700% (or 71 times) more 2 inch pipe than there is 6 inch pipe. In a weighted regression analysis, each type of pipe has an impact on the study that is proportionate to the quantity of pipe installed.

WITNESS: Steve Seelye

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.

RESPONSE:

a. Delta's proposed alternative rate mechanism was not designed to operate entirely on the basis of actual costs. In addition to establishing a lower bound on the common equity percentage, several other provisions could cause the mechanism to deviate from actual costs with respect to determining revenue requirements, including: (1) the use of an imputed capital structure consisting of 60% equity if Delta's actual equity percentage goes above 60%, (2) the continued removal of certain costs if they are disallowed in the rate case, and (3) using CPI-U as a performance-based measure.

With respect to the common equity percentage, Delta's proposed alternative rate mechanism would limit the equity percentage to 60%. Therefore, if actual common equity exceeds 60% then an imputed capital structure consisting of 60% equity would be utilized in the mechanism. Similarly, on the low end, the mechanism would limit the equity percentage to 43.5%. Therefore, if actual common equity falls below 43.5% then an imputed capital structure consisting of 43.5% equity would be utilized in the mechanism. Using an *imputed* capital structure if Delta's actual equity percentage falls below 43.5% is no different than using an *imputed* capital structure if Delta's actual equity percentage goes above 60.0%. In either case an imputed capital structure would be utilized.

The use of an imputed capital structure is consistent with the guidelines set by the U.S. Supreme Court in the *Bluefield* and *Hope* cases. The guidelines established by the U.S. Supreme Court in Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) require that a utility be allowed to earn a return that: (1) is comparable to alternative investment opportunities of corresponding risk, (2) will permit capital attraction on reasonable terms, and (3) will maintain a utility's financial integrity. A continued erosion in the equity component of Delta's capital structure would not be consistent with the charge of maintaining Delta's financial integrity or permitting capital attraction on reasonable terms. Utilizing an imputed capital structure in the determination of the revenue requirements in the rate case, as well as in the determination of revenue requirements in the alternative rate mechanism, would permit Delta to generate sufficient earned returns to reverse the trend of continued declined in the equity component of Delta's capital structure. It would also begin the process of process of returning Delta to financial health.

Even with the imputed capital structure, Delta would not return to financial health overnight. The use of an imputed capital structure would not *immediately* translate into a capital structure that is more representative of other gas distribution companies. It took a number of years for the equity component of Delta's capital structure to erode and it will take a number of years to rebuild it. However, reversing the trend will not be possible if the Commission utilizes Delta's test year end capital structure and a rate of return on equity similar to the one granted in Delta's last rate case. Pursuing this course would cause a continued deterioration in Delta's financial condition and a continued erosion in the equity component of its capital structure. Likewise, the trend cannot be reversed if the Commission uses an imputed capital structure to establish revenue requirements in the rate case but requires Delta to use actual equity in the application of the alternative rate mechanism beginning 6 or 7 months down the road. Using Delta's actual capital structure in the alternative rate mechanism would, in effect, nullify the use of an imputed capital structure in the rate case. With Delta's equity percentage being at such an alarmingly low level, if Delta is to have a *reasonable* chance of bringing its equity percentage within a *reasonable* range then it should be allowed to utilize its proposed imputed capital structure for setting rates, both in the rate case and in the alternative rate mechanism.

b. Attached is a revision of the example calculation of the Annual Adjustment Component for the 1998-99 budget-year that was previously submitted in response to Question No. 7(a) of the Commission Order dated June 4, 1999 in Case No. 99-046. This worksheet assumes an imputed average equity ratio of 43.5% rather than the estimated budget equity for the 1998-99 budget period in calculating the AAC. Since the instructions stated that the calculations were to assume Delta's current rate structure, we have applied the 11.6% ROE approved by the Commission in Delta's last rate case in these calculations. The supporting financial statements and other documents for the budget year were filed in response to Question 7 of the Commission Order dated June 4, 1999, in Case No. 99-046.

WITNESS: Part a – Steve Seelye
Martin J. Blake
Part b -- Randall Walker

Calculation of Annual Adjustment Component - (AAC)
By Rate Class Billing Blocks

The AAC adjusts rates upward or downward to compensate for expected departures from the Company's authorized return on common equity

AAC Period - July 1, 1998 through June 30, 1999
Filing Date -

Authorized Return on Common Equity	11.60%
Budget Equity 12 mos. avg.	$ 32,790,610
Budget Net Income Available for Common	2,640,200
Budget Return on Equity	8.05%
Annual Revenue 12 mos. prior to budget year	$ 38,922,061
Composite State and Federal Tax Rate	39.445%

Calculated Common Equity

$88,927,799	Average Capitalization - 12 month Budget Period
13,547,087	Less: Canada Mountain Adjustment
$75,380,712	Average Capitalization as Adjusted
43.5%	Imputed Equity Ratio
$32,790,610	Imputed Equity

Calculated Return-based Revenue Deficiency or (Excess)	$ 1,921,411
AAC Limitation (5% of prior year's revenue)	$ 1,946,103

AAC Amount to be Charged or (Credited) $\boxed{\$\ 1{,}921{,}411}$ **4.9% Increase**

	Firm Sales and Transportation					Interruptible Sales and Transportation				
	Block 0.1-200	Block 200.1-1000	Block 1001-5000	Block 5001-10000	Block over 10000	Block 1-1000	Block 1001-5000	Block 5001-10000	Block over 10000	Total
Net Budget Revenue During AAC Period										
Residential	10,198,500	-	-	-	-					10,198,500
Small Commercial	2,701,550	53,000	13,650	-	-					2,768,200
Large Commercial & Industrial	2,341,300	1,107,250	898,170	313,200	254,980	572,280	826,540	284,130	94,950	6,692,800
Total										$ 19,659,500
Amount to be Charged or (Credited)										Total
Residential	996,745	-	-	-	-	-	-	-	-	996,745
Commercial	264,035	5,180	1,334	-	-	-	-	-	-	270,549
Large Commercial & Industrial	228,826	108,217	87,782	30,610	24,920	55,932	80,781	27,769	9,280	654,118
Total										**$ 1,921,411**
Budgeted Mcf During AAC Period										Total
Residential	2,613,200	-	-	-	-					2,613,200
Commercial	654,500	21,200	6,500	-	-					682,200
Large Commercial & Industrial	765,700	442,900	427,700	208,800	231,800	287,300	635,800	315,700	189,900	3,505,600
Total										6,801,000
AAC Surcharge or (Credit) per Mcf										Composite
Residential	0.3814									**0.3814**
Commercial	0.4034	0.2443	0.2052							**0.3966**
Large Commercial & Industrial	0.2988	0.2443	0.2052	0.1466	0.1075	0.1947	0.1271	0.0880	0.0489	**0.1866**

Response to Question 1(b)
Commission Order Dated Sep. 2, 1999

DELTA NATURAL GAS COMPANY INC
CASE NO. 99-176

PSC DATA REQUEST

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.

RESPONSE:

The information requested is attached. Calculations by Randall Walker showing the volumetric and revenue adjustments to reflect normal temperatures for the last three years prior to the test period in this case are attached as Worksheet, pages 1 through 3. These calculations utilize the same temperature normalization format filed in this proceeding as Walker Exhibit 4. We no longer have the bill frequency data available to compute the revenue adjustment for 1994.

It should be pointed out, however, that the rates of return on common equity that would have been generated assuming normal weather patterns for the last 5 years bear no resemblance to the rates of return that Delta actually earned, as illustrated in Exhibit MJB-2 of the direct testimony of Martin J. Blake. It is actual earnings that impact a company's financial condition, not returns that **assume** normal weather. Delta's current financial is poor, and it is deteriorating. Clearly, the equity component of Delta's capital structure has been steadily eroding for the past 10 years, and this trend needs to be reversed for Delta to return to financial health.

The procedure of weather normalizing billing units used by the Commission in determining natural gas rates only produces a representative result on a going forward basis if there is no upward or downward trend in temperatures. If there is an upward trend in temperatures, there is a good chance that a natural gas utility would under-earn when the rates were subsequently implemented. During recent years, it appears that there has been an upward trend in temperatures experienced in this region. As a result, Delta has been underearning, as evidenced by the low rate of return that Delta has realized over the last ten years as shown on page 2 of Exhibit MJB-2.

Given Delta's poor current financial condition, the company could experience extreme financial difficulty while waiting for normal or below normal temperatures to materialize. It is not necessary to make Delta's earning like a bet on the weather. In addition to weather normalizing when determining rates, the Commission could also allow weather normalizing in applying rates, which the WNA tariff or the Alt Reg Plan or a combination of the two mechanisms would accomplish. Unless a tariffs similar to the WNA tariff and Alt Reg Plan are utilized, the methodology for weather normalizing in determining rates exposes Delta to considerable financial risk resulting from the vagaries of weather or from a downtown in average temperatures. The WNA tariff and Alt Reg Plan would help provide Delta with an opportunity to earn the return that the Commission has authorized irrespective of any trend in temperatures and would be consistent with the procedure of weather normalizing billing units used by the Commission in determining gas service rates.

Witness: Temp Norm Calculations – Randall Walker
ROR Calculations – John F. Hall
Discussion – Martin J. Blake

RESPONSE TO PSC ITEM 2:

LINE NUMBER		WALKER EXHIBIT	NET OF TAXES @ 39.445%	NI ACTUAL	NI ADJUSTED	EQUITY ACTUAL	EQUITY ADJUSTED	ROE ACTUAL	ROE ADJUSTED
1	1998	$ 1,693,458	$ 1,025,473	$ 2,232,441	$ 3,257,914	$ 28,351,812	$ 29,377,285	7.87%	11.09%
2	1997	(331,710)	(200,867)	2,038,238	1,837,371	28,255,698	28,054,831	7.21%	6.55%
3	1996	(901,360)	(545,819)	2,236,779	1,690,960	28,248,744	27,702,925	7.92%	6.10%
4	1995	85,328	51,670	2,486,064	2,537,734	21,645,813	21,697,483	11.49%	11.70%

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

!2-Months Ended December 31, 1997

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,727	4,727
Actual Heating Degree Days	4,919	4,972
Normal over (under) Actual	(192)	(245)

	(1) Total Mcf Sales	(2) Non-Temp Sensitive Mcf *(Aug-Sep)*	(3) Non-Temp Sensitive Mcf *(full year)*	(4) Non-Temp Sensitive Mcf per Day	(5) Temp Sensitive Mcf	(6) Actual Degree Days	(7) Mcf per Degree Day	(8) Degree Day Deficiency from Normal	(9) Temperature Normalization Adjustment (Mcf)	(10) Net Revenue per Mcf	(11) Net Revenue Adjustment
			col (2) x 6	*col (3) / 365*	*col (1) - col (3)*		*col (5) / col (6)*		*col (7) / col (8)*		*col (9) / col (10)*
Residential-Firm Sales	2,527,891	67,688	406,128	1,113	2,121,763	4,919	431	(192)	(82,817)	$ 2.4650	(204,145)
0.1 - 1000 Mcf / mo.	*2,527,891*										
Commercial-Firm Sales	1,575,278	68,683	412,098	1,129	1,163,180	4,919	236	(192)	(45,402)		(110,780)
0.1 - 1000 Mcf / mo.	*1,488,914*								*(42,912)*	$ 2.4650	*(105,779)*
1000.1 - 5000 Mcf / mo.	*74,259*								*(2,140)*	$ 2.0650	*(4,420)*
5000.1 - 10000 Mcf / mo.	*12,105*								*(349)*	$ 1.6650	*(581)*
10000.1 and over Mcf / mo.	-								-	$ 1.2650	-
Industrial-Firm Sales	207,300	18,380	110,280	302	97,020	4,919	20	(192)	(3,787)		(8,914)
0.1 - 1000 Mcf / mo.	*155,690*								*(2,844)*	$ 2.4650	*(7,011)*
1000.1 - 5000 Mcf / mo.	*45,625*								*(833)*	$ 2.0650	*(1,721)*
5000.1 - 10000 Mcf / mo.	*5,985*								*(109)*	$ 1.6650	*(182)*
10000.1 and over Mcf / mo.	-								-	$ 1.2650	-
Com./Indust. Firm Transport.	730,390	113,428	680,568	1,865	49,822	4,919	10	(192)	(1,945)		(3,794)
0.1 - 1000 Mcf / mo.	*175,848*								*(468)*	$ 2.4650	*(1,154)*
1000.1 - 5000 Mcf / mo.	*306,722*								*(817)*	$ 2.0650	*(1,686)*
5000.1 - 10000 Mcf / mo.	*111,524*								*(297)*	$ 1.6650	*(494)*
10000.1 and over Mcf / mo.	*136,296*								*(363)*	$ 1.2650	*(459)*
Com./Indust.-Interruptible Sales	97,697	4,656	27,936	77	69,761	4,919	14	(192)	(2,723)		(4,077)
0.1 - 1000 Mcf / mo.	*50,201*								*(1,399)*	$ 1.7000	*(2,379)*
1000.1 - 5000 Mcf / mo.	*45,494*								*(1,268)*	$ 1.3000	*(1,648)*
5000.1 - 10000 Mcf / mo.	*2,002*								*(56)*	$ 0.9000	*(50)*
10000.1 and over Mcf / mo.	-								-	$ 0.5000	-
	97,697										
							Total		**(136,673)**		**$ (331,710)**

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

!2-Months Ended December 31, 1996

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,711	4,711
Actual Heating Degree Days	5,194	5,087
Normal over (under) Actual	(483)	(376)

	(1) Total Mcf Sales	(2) Non-Temp Sensitive Mcf (Aug-Sep)	(3) Non-Temp Sensitive Mcf (full year)	(4) Non-Temp Sensitive Mcf per Day	(5) Temp Sensitive Mcf	(6) Actual Degree Days	(7) Mcf per Degree Day	(8) Degree Day Deficiency from Normal	(9) Temperature Normalization Adjustment (Mcf)	(10) Net Revenue per Mcf	(11) Net Revenue Adjustment
			col (2) x 6	col (3) / 365	col (1) - col (3)		col (5) / col (6)		col (7) / col (8)		col (9) / col (10)
Residential-Firm Sales	2,704,756	66,759	400,554	1,097	2,304,202	5,194	444	(483)	(214,272)	$ 2.4650	(528,181)
0.1 - 1000 Mcf / mo.	2,704,756										
Commercial-Firm Sales	1,648,828	66,419	398,514	1,092	1,250,314	5,194	241	(483)	(116,269)		(283,824)
0.1 - 1000 Mcf / mo.	1,564,340								(110,311)	$ 2.4650	(271,917)
1000.1 - 5000 Mcf / mo.	70,436								(4,967)	$ 2.0650	(10,257)
5000.1 - 10000 Mcf / mo.	14,052								(991)	$ 1.6650	(1,650)
10000.1 and over Mcf / mo.	-								-	$ 1.2650	-
Industrial-Firm Sales	189,701	8,272	49,632	136	140,069	5,194	27	(483)	(13,025)		(30,692)
0.1 - 1000 Mcf / mo.	140,184								(9,625)	$ 2.4650	(23,726)
1000.1 - 5000 Mcf / mo.	47,490								(3,261)	$ 2.0650	(6,733)
5000.1 - 10000 Mcf / mo.	2,027								(139)	$ 1.6650	(232)
10000.1 and over Mcf / mo.	-								-	$ 1.2650	-
Com./Indust. Firm Transport.	597,098	54,751	328,506	900	268,592	5,194	52	(483)	(24,977)		(49,171)
0.1 - 1000 Mcf / mo.	163,338								(6,833)	$ 2.4650	(16,842)
1000.1 - 5000 Mcf / mo.	235,348								(9,845)	$ 2.0650	(20,329)
5000.1 - 10000 Mcf / mo.	89,651								(3,750)	$ 1.6650	(6,244)
10000.1 and over Mcf / mo.	108,761								(4,550)	$ 1.2650	(5,755)
Com./Indust.-Interruptible Sales	117,369	8,391	50,346	138	67,023	5,194	13	(483)	(6,233)		(9,493)
0.1 - 1000 Mcf / mo.	68,905								(3,659)	$ 1.7000	(6,220)
1000.1 - 5000 Mcf / mo.	45,013								(2,390)	$ 1.3000	(3,107)
5000.1 - 10000 Mcf / mo.	3,451								(183)	$ 0.9000	(165)
10000.1 and over Mcf / mo.									-	$ 0.5000	-
							Total		**(374,776)**	$	**(901,360)**

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

12-Months Ended December 31, 1995

	Cycle Billing Basis	Calendar Basis
Normal Heating Degree Days	4,717	4,717
Actual Heating Degree Days	4,668	4,847
Normal over (under) Actual	49	(130)

	(1) Total Mcf Sales	(2) Non-Temp Sensitive Mcf (Aug-Sep)	(3) Non-Temp Sensitive Mcf (full year)	(4) Non-Temp Sensitive Mcf per Day	(5) Temp Sensitive Mcf	(6) Actual Degree Days	(7) Mcf per Degree Day	(8) Degree Day Deficiency from Normal	(9) Temperature Normalization Adjustment (Mcf)	(10) Net Revenue per Mcf	(11) Net Revenue Adjustment
			col (2) x 6	col (3) / 365	col (1) - col (3)		col (5) / col (6)		col (7) / col (8)		col (9) / col (10)
Residential-Firm Sales	2,345,258	61,778	370,668	1,016	1,974,590	4,668	423	49	20,727	$ 2.4650	51,093
0.1 - 1000 Mcf / mo.	*2,345,258*										
Commercial-Firm Sales	1,405,796	58,658	351,948	964	1,053,848	4,668	226	49	11,062		27,049
0.1 - 1000 Mcf / mo.	*1,342,918*								*10,567*	$ *2.4650*	*26,049*
1000.1 - 5000 Mcf / mo.	*55,974*								*440*	$ *2.0650*	*910*
5000.1 - 10000 Mcf / mo.	*6,904*								*54*	$ *1.6650*	*90*
10000.1 and over Mcf / mo.									-	$ *1.2650*	-
Industrial-Firm Sales	154,394	13,102	78,612	215	75,782	4,668	16	49	795		1,861
0.1 - 1000 Mcf / mo.	*106,155*								*547*	$ *2.4650*	*1,348*
1000.1 - 5000 Mcf / mo.	*47,856*								*247*	$ *2.0650*	*509*
5000.1 - 10000 Mcf / mo.	*383*								*2*	$ *1.6650*	*3*
10000.1 and over Mcf / mo.	-								-	$ *1.2650*	-
Com./Indust. Firm Transport.	475,847	45,120	270,720	742	205,127	4,668	44	49	2,153		4,225
0.1 - 1000 Mcf / mo.	*134,432*								*608*	$ *2.4650*	*1,499*
1000.1 - 5000 Mcf / mo.	*181,117*								*820*	$ *2.0650*	*1,692*
5000.1 - 10000 Mcf / mo.	*63,814*								*289*	$ *1.6650*	*481*
10000.1 and over Mcf / mo.	*96,484*								*437*	$ *1.2650*	*552*
Com./Indust.-Interruptible Sales	107,647	6,962	41,772	114	65,875	4,668	14	49	691		1,101
0.1 - 1000 Mcf / mo.	*78,461*								*504*	$ *1.7000*	*857*
1000.1 - 5000 Mcf / mo.	*29,186*								*187*	$ *1.3000*	*244*
5000.1 - 10000 Mcf / mo.									-	$ *0.9000*	-
10000.1 and over Mcf / mo.									-	$ *0.5000*	-
							Total		**35,430**		**$ 85,328**

3

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

PSC DATA REQUEST

3. Refer to Delta's response to Item 59 of the Commissions 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%. Excluded variances that are the lesser of $5,000 or 5%.

RESPONSE:
See attached

WITNESS: John Hall

Delta Natural Gas Company, Inc.
Case No. 99-176
PSC Item 3

Budget Variances

by account

for the years 1994,1995, 1996, & 1997

1.403.000 - DEPRECIATION EXPENSE JFH

	1994	1995	1996	1997
Actual	1,930,790	2,140,960	2,471,853	2,896,052
Budget	1,918,800	2,106,000	2,322,000	2,852,400
Variance	*11,990*	*34,960*	*149,853*	*43,652*
% of budget	*0.62%*	*1.66%*	*6.45%*	*1.53%*
% of actual	*0.62%*	*1.63%*	*6.06%*	*1.51%*

1.408.010 - LICENSE & PRIVILEGE FEES JFH

	1994	1995	1996	1997
Actual	2,954	1,985	12,245	1,519
Budget	10,000	10,000	10,000	12,000
Variance	*-7,046*	*-8,015*	*2,245*	*-10,481*
% of budget	*-70.46%*	*-80.15%*	*22.45%*	*-87.34%*
% of actual	*-238.52%*	*-403.78%*	*18.33%*	*-689.99%*

	These fees are based on taxable net income, which is not budgeted. This account is budgeted based on long term history, assuming normal taxable income.
1994	Taxable income was only $1,268,808 (compared to 2,621,000 book income) due to timing items. Therefore, license fees on that amount were lower than budgeted.
1995	Taxable income in fiscal 1994 was only $88,044 due to timing items. Therefore, license fees (paid during fiscal 1995) on that amount were minimal.
1996	Taxable income in fiscal 1995 was $3,434,615 due to timing items. Therefore, license fees (paid during fiscal 1996) were higher than budget.
1997	Delta experienced an $1,477,144 tax loss in fiscal 1996. Therefore, license fees (paid during fiscal 1997) were minimal.

1.408.020 - PROPERTY TAXES JFH

	1994	1995	1996	1997
Actual	389,800	426,000	544,418	574,949
Budget	392,400	438,000	445,800	580,200
Variance	*-2,600*	*-12,000*	*98,618*	*-5,251*
% of budget	*-0.66%*	*-2.74%*	*22.12%*	*-0.91%*

	1994	1995	1996	1997
% of actual	*-0.67%*	*-2.82%*	*18.11%*	*-0.91%*

1996	The state raised the Company's 12/31/94 property tax assessment an unexpected and unprecedented amount. The company was not aware of this increase until near the end of calendar 1995, and at that time began booking enough expense to have the increased assessment booked by 6/96.

1.408.03 - Payroll Taxes JFH

	1994	1995	1996	1997
Actual	464,152	420,525	467,752	472,614
Budget	405,600	418,200	429,200	442,200
Variance	*58,552*	*2,325*	*38,552*	*30,414*
% of budget	*14.44%*	*0.56%*	*8.98%*	*6.88%*
% of actual	*12.61%*	*0.55%*	*8.24%*	*6.44%*

1994	The variance of 14.44% is due largely to the Bonus that was paid by Delta to its employees.

1.409.010 - CURRENT FED INC TAX JFH

	1994	1995	1996	1997
Actual	17,700	895,500	-241,100	376,200
Budget	0	0	0	0
Variance	*17,700*	*895,500*	*-241,100*	*376,200*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

	For budget purposes, Delta does not break out income taxes between deferred, currents, federal, state, etc. Therefore, these accounts need to be combined for analysis purposes. See the attachment no. 1 (at the end of the variances) which consolidates these accounts. *In total, the variations can be explained as follows:*
1994	Income tax expense was $171,400 higher than budget. This is primarily a result of regulated net income being $426,900 higher than budgeted.
1995	Income tax expense was $358,400 lower than budget. This is primarily a result of regulated net income being $428,100 lower than budgeted.
1996	Income tax expense was 164,200 higher than budgeted. This is primarily a result *of regulated net income being $282,400 higher than budgeted.*
1997	Income tax expense was $357,800 higher than budgeted. This is primarily a result of regulated net income being $628,500 higher than budgeted.
	see attachment no. 1 following the variances

1.409.020 - CURRENT STATE INC TAX JFH

	1994	1995	1996	1997
Actual	36,700	134,700	-315,100	-61,100
Budget	0	0	0	0
Variance	*36,700*	*134,700*	*-315,100*	*-61,100*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see 1.409.01 & attachment no. 1 following the variances

1.409.070 - ESTIMATED INTERIM INCOME TAXES JFH

	1994	1995	1996	1997
Actual	0	0	0	0
Budget	0	1,068,500	1,023,500	414,000
Variance	*0*	*-1,068,500*	*-1,023,500*	*-414,000*
% of budget	...	*-100.00%*	*-100.00%*	*-100.00%*
% of actual	...	...	...	...

see 1.409.01 & attachment no. 1 following the variances

1.409.080 - INCOME TAXES NON-REGULATED JFH

	1994	1995	1996	1997
Actual	28,700	32,900	36,200	23,900
Budget	0	0	27,400	26,300
Variance	*28,700*	*32,900*	*8,800*	*-2,400*
% of budget	...	...	*32.12%*	*-9.13%*
% of actual	*100.00%*	*100.00%*	*24.31%*	*-10.04%*

see 1.409.01 & attachment no. 1 following the variances

1.410.000 - DEFERRED INCOME TAXES JFH

	1994	1995	1996	1997
Actual	1,202,700	-248,700	1,814,900	527,700
Budget	0	0	0	0
Variance	*1,202,700*	*-248,700*	*1,814,900*	*527,700*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see 1.409.01 & attachment no. 1 following the variances

1.411.000 - INVESTMENT TAX CREDIT NET JFH

	1994	1995	1996	1997
Actual	-71,500	-71,400	-71,000	-71,000
Budget	1,014,200	0	0	0
Variance	*-1,085,700*	*-71,400*	*-71,000*	*-71,000*

	1994	1995	1996	1997
% of budget	*-107.05%*	...	...	...
% of actual	*1518.46%*	*100.00%*	*100.00%*	*100.00%*

see 1.409.01 & attachment no. 1 following the variances

1.415.010 - LABOR SERVICE REVENUE JFH

Actual	-11,138	-6,216	-6,861	-6,363
Budget	-7,200	-9,600	-4,800	-6,000
Variance	*-3,938*	*3,385*	*-2,061*	*-363*
% of budget	*54.69%*	*-35.26%*	*42.94%*	*6.05%*
% of actual	*35.36%*	*-54.46%*	*30.04%*	*5.70%*

1.415.020 - MERCHANDISING REVENUE JFH

Actual	-58,571	-54,110	-46,147	-60,352
Budget	-54,000	-60,000	-60,000	-48,000
Variance	*-4,571*	*5,890*	*13,854*	*-12,352*
% of budget	*8.46%*	*-9.82%*	*-23.09%*	*25.73%*
% of actual	*7.80%*	*-10.89%*	*-30.02%*	*20.47%*

Variance due to incorrect estimates. Budget based on 18 month prior average.

1.415.030 - SALES TAX COMMISSION JFH

Actual	-5,112	-1,801	-6,365	-7,119
Budget	-2,400	-3,600	-2,400	-4,200
Variance	*-2,712*	*1,799*	*-3,965*	*-2,919*
% of budget	*113.00%*	*-49.97%*	*165.21%*	*69.50%*
% of actual	*53.05%*	*-99.89%*	*62.29%*	*41.00%*

1.416.010 - LABOR SERVICE EXPENSE JLC

Actual	10,098	8,433	6,118	5,747
Budget	0	0	0	0
Variance	*10,098*	*8,433*	*6,118*	*5,747*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.416.020 - MERCHANDISING EXPENSE JFH

	1994	1995	1996	1997
Actual	44,857	34,438	36,762	48,115
Budget	37,200	55,200	36,000	36,000
Variance	***7,657***	***-20,762***	***762***	***12,115***
% of budget	***20.58%***	***-37.61%***	***2.12%***	***33.65%***
% of actual	***17.07%***	***-60.29%***	***2.07%***	***25.18%***

Variance due to incorrect estimates. Budget based on 18 month prior average.

1.418.010 - NET EARNINGS OF SUBSIDIARY JFH

	1994	1995	1996	1997
Actual	-516,263	-529,131	-594,350	-316,938
Budget	-416,600	-407,100	-574,900	-499,900
Variance	***-99,663***	***-122,031***	***19,450***	***182,962***
% of budget	***23.92%***	***29.98%***	***-3.38%***	***-36.60%***
% of actual	***19.30%***	***23.06%***	***-3.27%***	***-57.73%***

1994	The major explanation for this variance is with Delta Resources. DR sales were $98,000 higher than budget primarily caused by selling 84,000 mcf than budgeted at 1.65 per mcf higher than budgeted.
1995	$111,500 of the variance again is explained with Delta Resources. DR sales were 102,121 mcf higher than budget. The rate per mcf was 1.66 higher than budgeted.
1997	In 1997, the budget variance was again due largely to DR. DR came in $297,800 under budget. Volumes were 293,055 greater than budget, but the net price per mcf was down 1.62, which drove operating profit down to .03 per mcf. Offsetting the DR decrease was the fact that Enpro came in $75,900 over budget, caused by increased production.

1.419.000 - INTEREST & DIVIDEND INCOME JFH

	1994	1995	1996	1997
Actual	-25,951	-24,639	-23,452	-30,671
Budget	-12,000	-19,200	-20,400	-20,400
Variance	***-13,951***	***-5,439***	***-3,052***	***-10,271***
% of budget	***116.26%***	***28.33%***	***14.96%***	***50.35%***
% of actual	***53.76%***	***22.07%***	***13.01%***	***33.49%***

This account was very consistent throughout 94, 95 and 96 at $26,000; 24,600 and 23,500, respectively, and consistently over budget. There are no large or unusual items, the budget was just understated. In 1997, the account increased to $30,671. This is attributable to an increase in dividends paid on life insurance policies ($2,167) and a $3,273 payment received from the IRS for interest on overpayment of tax.

1.421.000 - MISC NON OPERATING INCOME JFH

	1994	1995	1996	1997
Actual	-1,728	-24,073	-19,558	-5,704
Budget	-3,600	-2,400	-2,400	-10,800
Variance	*1,872*	*-21,673*	*-17,158*	*5,096*
% of budget	*-52.00%*	*903.04%*	*714.92%*	*-47.19%*
% of actual	*-108.33%*	*90.03%*	*87.73%*	*-89.34%*

1995	$21,000 to record unbudgeted net gain on property from the sale of office land on Pine Street in Pineville
1996	$10,782 to record unbudgeted revenue from the sale of engineering maps; $4,700 in unbudgeted revenue associated with the sale of property in Nicholasville
1997	In 1997, the budget amount was adjusted to anticipated non-recurring items, as had occurred in the previous two years. No non-recurring items occurred in 1997, thus the account came in under budget.

1.426.020 - LIFE INSURANCE CO. BENEFICIARY JLC

Actual	-16,142	-15,513	-9,202	-8,426
Budget	-20,100	-15,000	-15,000	-15,500
Variance	*3,958*	*-513*	*5,798*	*7,074*
% of budget	*-19.69%*	*3.42%*	*-38.65%*	*-45.64%*
% of actual	*-24.52%*	*3.31%*	*-63.01%*	*-83.95%*

1996	The dividends for Key Man Insurance now being paid directly to the Company. The budget was overstated due to this.
1997	The dividends for Key Man Insurance now being paid directly to the Company. The budget was overstated due to this.

1.427.000 - INTEREST ON LONG TERM DEBT JFH

Actual	1,879,526	1,879,442	1,851,768	2,997,393
Budget	1,837,200	1,893,600	1,876,800	1,833,600
Variance	*42,326*	*-14,158*	*-25,032*	*1,163,793*
% of budget	*2.30%*	*-0.75%*	*-1.33%*	*63.47%*
% of actual	*2.25%*	*-0.75%*	*-1.35%*	*38.83%*

1997	Financing was not included in budget

1.428.000 - AMORT OF DEBT EXPENSES JFH

Actual	91,404	88,800	152,523	115,366
Budget	75,400	82,800	88,800	88,800
Variance	*16,004*	*6,000*	*63,723*	*26,566*
% of budget	*21.23%*	*7.25%*	*71.76%*	*29.92%*

	1994	1995	1996	1997
% of actual	*17.51%*	*6.76%*	*41.78%*	*23.03%*

1994	October 1993 financing not included in budget
1996	Record related debt expense for Canada Mountain
1997	July 1996 financing not included in budget

1.431.010 - INTEREST ON CUSTOMER DEPOSITS JFH

	1994	1995	1996	1997
Actual	25,055	23,522	21,779	17,647
Budget	30,000	27,600	25,200	23,400
Variance	*-4,945*	*-4,078*	*-3,421*	*-5,753*
% of budget	*-16.48%*	*-14.78%*	*-13.58%*	*-24.59%*
% of actual	*-19.74%*	*-17.34%*	*-15.71%*	*-32.60%*

1997	Estimated based on Actual at 12/31/95

1.431.020 - INTEREST ON SHORT-TERM DEBT JFH

	1994	1995	1996	1997
Actual	206,766	407,271	802,739	565,084
Budget	592,000	351,000	625,000	1,849,000
Variance	*-385,234*	*56,271*	*177,739*	*-1,283,916*
% of budget	*-65.07%*	*16.03%*	*28.44%*	*-69.44%*
% of actual	*-186.31%*	*13.82%*	*22.14%*	*-227.21%*

1994	Decrease due primarily due to proceeds from sale of debentures and common stock in October 1993 being used to repay short-term debt
1995	Increased average short-term borrowings and increased average interest rates
1996	Increased average short-term borrowings and increased average interest rates
1997	Decrease due primarily to decreased average short-term borrowing as short-term debt repaid with net proceeds from sale of long-term debt during July 1996

1.480.010 - GS RATE SALES RESIDENTIAL JFH

	1994	1995	1996	1997
Actual	-16,596,958	-14,772,248	-16,538,970	-19,693,293
Budget	-15,080,500	-17,146,500	-16,697,900	-16,005,900
Variance	*-1,516,458*	*2,374,252*	*158,930*	*-3,687,393*
% of budget	*10.06%*	*-13.85%*	*-0.95%*	*23.04%*
% of actual	*9.14%*	*-16.07%*	*-0.96%*	*18.72%*

	Budgets are based on calculations using MCF & degree days. These two factors greatly affect accuracy of budget figures.
1994	Actual degree days & MCF increased.
1995	Actual degree days & MCF decreased.

	1994	1995	1996	1997

1997	Actual degree days & MCF decreased slightly, therefore cost of gas increased causing revenues to increase also.

1.480.020 - GS RATE SALES OTHER COMMERCIAL JFH

	1994	1995	1996	1997
Actual	-9,554,883	-8,570,398	-9,675,694	-11,830,890
Budget	-7,995,700	-9,749,900	-9,048,400	-8,665,600
Variance	*-1,559,183*	*1,179,502*	*-627,294*	*-3,165,290*
% of budget	*19.50%*	*-12.10%*	*6.93%*	*36.53%*
% of actual	*16.32%*	*-13.76%*	*6.48%*	*26.75%*

same as account 1.480.01

1.480.030 - GS RATE SALES INDUSTRIAL JFH

	1994	1995	1996	1997
Actual	-901,582	-783,401	-1,054,585	-1,354,822
Budget	-577,600	-810,500	-736,000	-794,200
Variance	*-323,982*	*27,099*	*-318,585*	*-560,622*
% of budget	*56.09%*	*-3.34%*	*43.29%*	*70.59%*
% of actual	*35.93%*	*-3.46%*	*30.21%*	*41.38%*

Change in MCF cuased variances

1.481.020 - INTERRUPTIBLE RATE COMMERCIAL JFH

	1994	1995	1996	1997
Actual	-107,962	-102,196	-112,021	-146,496
Budget	-85,900	-101,400	-90,500	-88,800
Variance	*-22,062*	*-796*	*-21,521*	*-57,696*
% of budget	*25.68%*	*0.79%*	*23.78%*	*64.97%*
% of actual	*20.43%*	*0.78%*	*19.21%*	*39.38%*

Variances are due to fluctuations in GCR rates.

1.481.030 - INTERRUPTIBLE RATE INDUSTRIAL JFH

	1994	1995	1996	1997
Actual	-769,169	-464,283	-428,868	-535,510
Budget	-1,086,300	-831,600	-651,800	-414,700
Variance	*317,131*	*367,317*	*222,932*	*-120,810*
% of budget	*-29.19%*	*-44.17%*	*-34.20%*	*29.13%*
% of actual	*-41.23%*	*-79.11%*	*-51.98%*	*22.56%*

Variances are due to fluctuations in GCR rates

	1994	1995	1996	1997

1.488.010 - COLLECTION REVENUE JFH

	1994	1995	1996	1997
Actual	-76,375	-60,925	-60,720	-71,420
Budget	-48,000	-72,000	-69,600	-60,000
Variance	*-28,375*	*11,075*	*8,880*	*-11,420*
% of budget	*59.11%*	*-15.38%*	*-12.76%*	*19.03%*
% of actual	*37.15%*	*-18.18%*	*-14.62%*	*15.99%*

This account represents the amount of collection fees charged to customers who have not paid, but want turned back on after paying their bill. This account is budgeted based on the prior year amounts. Therefore, if the number of customers who do not pay is higher for a given year the collection revenue will be higher. The next year's budgeted amount will be higher because of the higher collection revenue from the prior year. Factors causing this variance include colder winters with larger bills and other economic factors.

1.488.020 - RECONNECT REVENUE JFH

	1994	1995	1996	1997
Actual	-29,260	-28,525	-30,285	-33,400
Budget	-31,200	-30,000	-28,800	-28,800
Variance	*1,940*	*1,475*	*-1,485*	*-4,600*
% of budget	*-6.22%*	*-4.92%*	*5.16%*	*15.97%*
% of actual	*-6.63%*	*-5.17%*	*4.90%*	*13.77%*

1.488.040 - BAD CHECK REVENUE JFH

	1994	1995	1996	1997
Actual	-3,000	-2,565	-2,890	-3,475
Budget	-3,200	-2,400	-2,400	-2,400
Variance	*200*	*-165*	*-490*	*-1,075*
% of budget	*-6.25%*	*6.88%*	*20.42%*	*44.79%*
% of actual	*-6.67%*	*6.43%*	*16.96%*	*30.94%*

1.489.020 - OFF SYSTEM TRANSP REVENUE JFH

	1994	1995	1996	1997
Actual	-622,905	-461,857	-417,915	-382,158
Budget	-572,400	-572,400	-487,200	-401,100
Variance	*-50,505*	*110,543*	*69,285*	*18,942*
% of budget	*8.82%*	*-19.31%*	*-14.22%*	*-4.72%*
% of actual	*8.11%*	*-23.93%*	*-16.58%*	*-4.96%*

	1994	1995	1996	1997

Actual revenues in this account have steadily declined over the last several years due to the decline of locally produced natural gas. These revenues are wholly dependent upon the efforts of local producers to successfully drill new production wells to sustain deliverability. As an example, Southern Gas Company delivered to Delta's system for transportation 1,396,566 Dth, 870,082 Dth, and 799,515 Dth during fiscal 1994, 1995, and 1996 respectively. Delta is not able to forecast, with a high degree of accuracy, the rate of decline of existing production volumes nor the addition of new supplies for off-system transportation volumes.

1.489.040 - ON SYSTEM TRANSP REVENUE JFH

	1994	1995	1996	1997
Actual	-2,310,166	-2,587,607	-2,913,319	-3,213,951
Budget	-2,263,900	-2,278,400	-2,472,900	-2,711,600
Variance	*-46,266*	*-309,207*	*-440,419*	*-502,351*
% of budget	*2.04%*	*13.57%*	*17.81%*	*18.53%*
% of actual	*2.00%*	*11.95%*	*15.12%*	*15.63%*

1995,96 & 97	MCF's increased more than budgeted

1.753.010 - WELLS & GATHERING PAYROLL JLC

	1994	1995	1996	1997
Actual	39,908	27,936	22,755	17,904
Budget	0	0	0	0
Variance	*39,908*	*27,936*	*22,755*	*17,904*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.753.020 - WELLS & GATHERING MISC ALH

	1994	1995	1996	1997
Actual	1,192	498	7,065	1,064
Budget	6,200	2,400	1,200	1,200
Variance	*-5,008*	*-1,902*	*5,865*	*-136*
% of budget	*-80.77%*	*-79.25%*	*488.75%*	*-11.33%*
% of actual	*-420.13%*	*-381.93%*	*83.01%*	*-12.78%*

1994	Budget was $5,000 not $6,200; Repeat from 1992 and 1993
1996	Fauste Oil expenses charged to wrong account; Correct Account 1.754.02

1.754.010 - COMPRESSOR STATION PAYROLL JLC

	1994	1995	1996	1997
Actual	53,636	53,376	53,160	51,264
Budget	0	0	0	0
Variance	*53,636*	*53,376*	*53,160*	*51,264*
% of budget	*...*	*...*	*...*	*...*
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.754.020 - COMPRESSOR STATION MISC. ALH

Actual	48,638	55,423	37,732	39,977
Budget	60,000	60,000	60,000	36,000
Variance	*-11,362*	*-4,577*	*-22,268*	*3,977*
% of budget	*-18.94%*	*-7.63%*	*-37.11%*	*11.05%*
% of actual	*-23.36%*	*-8.26%*	*-59.02%*	*9.95%*

Same as 1.765.020

1.764.010 - MNT WELLS & GATHERING PAYROLL JLC

Actual	1,641	232	1,711	2,996
Budget	0	0	0	0
Variance	*1,641*	*232*	*1,711*	*2,996*
% of budget	*...*	*...*	*...*	*...*
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.764.020 - MNT WELLS & GATHERING OTHER ALH

Actual	470	824	1,984	439
Budget	2,400	2,400	2,400	2,400
Variance	*-1,930*	*-1,576*	*-416*	*-1,961*
% of budget	*-80.42%*	*-65.67%*	*-17.33%*	*-81.71%*
% of actual	*-410.64%*	*-191.26%*	*-20.97%*	*-446.70%*

1.765.010 - MNT COMPRESSOR STATION PAYROLL JLC

Actual	5,196	3,234	2,146	2,629
Budget	0	0	0	0
Variance	*5,196*	*3,234*	*2,146*	*2,629*
% of budget	*...*	*...*	*...*	*...*

	1994	1995	1996	1997
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.765.020 - MNT COMPRESSOR STATION OTHER ALH

	1994	1995	1996	1997
Actual	23,887	15,119	19,781	15,076
Budget	36,000	30,000	30,000	24,000
Variance	*-12,113*	*-14,881*	*-10,219*	*-8,924*
% of budget	*-33.65%*	*-49.60%*	*-34.06%*	*-37.18%*
% of actual	*-50.71%*	*-98.43%*	*-51.66%*	*-59.19%*

Historical expenditures have not supported the budget amount in this account. This budget has been reduced to its current level in an effort to reduce the budget variance.

1.803.000 - PURCHASED GAS JFH

	1994	1995	1996	1997
Actual	14,481,772	12,531,799	13,220,922	19,878,908
Budget	12,095,400	15,571,700	13,657,200	12,111,700
Variance	*2,386,372*	*-3,039,901*	*-436,278*	*7,767,208*
% of budget	*19.73%*	*-19.52%*	*-3.19%*	*64.13%*
% of actual	*16.48%*	*-24.26%*	*-3.30%*	*39.07%*

	Budgets are based on calculations using MCF & degree days. These two factors greatly affect accuracy of budget figures.
1994	Actual degree days & MCF increased.
1995	Actual degree days & MCF decreased.
1997	Actual degree days & MCF decreased slightly, but average cost of gas increased causing gas cost to go up.

1.816.010 - CM WELLS EXPENSES - PAYROLL JLC

	1994	1995	1996	1997
Actual	0	0	0	17,036
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*17,036*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.816.020 - CM WELLS EXPENSES - MISC ALH

	1994	1995	1996	1997
Actual	0	0	0	3,706

	1994	1995	1996	1997
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*3,706*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.818.010 - CM COMPRESSOR STATION EXPENSES - PAYROLL JLC

	1994	1995	1996	1997
Actual	0	0	0	15,676
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*15,676*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.818.020 - CM COMPRESSOR STATION EXPENSES - MISC ALH

	1994	1995	1996	1997
Actual	0	0	247	8,577
Budget	0	0	0	0
Variance	*0*	*0*	*247*	*8,577*
% of budget	...	...	...	...
% of actual	...	...	*100.00%*	*100.00%*

1997	During the development of Canada Mountain, there was some uncertainty about how the accounts should be structured. This account was established after the budgeting process. For year ending 6/30/97 $12,000 was budgeted in 4.818.02. Later the charges accumulated in 1.818.02.

1.824.020 - CM OTHER UNDERGROUND STORAGE EXPENSES - MISC ALH

	1994	1995	1996	1997
Actual	0	0	0	5,564
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*5,564*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1997	The charges to this account during fiscal 1997 were composed of $2,000 to Arthur Andersen and $3,564 to Griffith Engineering for consulting fees pertaining to Canada Mountain. These costs were nonrecurring in nature and were not anticipated at the time the budget for fiscal year 1997 was being developed.

1.825.000 - CM STORAGE WELL ROYALTIES/RENTS ALH

	1994	1995	1996	1997
Actual	0	0	21,790	48,650
Budget	0	0	0	0
Variance	*0*	*0*	*21,790*	*48,650*
% of budget	...	...	...	...
% of actual	...	...	*100.00%*	*100.00%*

This account pertains to storage well rents and royalties. It is very precise because the payments are set by the terms of legal documents and are readily determinable. The payment schedule has remained basically unchanged since storage operations commenced. Account 4.825 is where expenses were likely budgeted.

1.831.020 - CM MAINTENANCE STRUCTURES & IMPROVEMENTS - MISC ALH

Actual	0	0	0	650
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*650*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.832.010 - CM MAINT OF RESERVOIRS AND WELLS - PAYROLL JLC

Actual	0	0	0	424
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*424*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.832.020 - CM MAINTENANCE OF RESERVOIRS AND WELLS - MISC ALH

Actual	0	0	0	5
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*5*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.833.020 - CM MAINTENANCE OF LINES - MISC ALH

Actual	0	0	81	760
Budget	0	0	0	0
Variance	*0*	*0*	*81*	*760*

	1994	1995	1996	1997
% of budget	...	...	...	...
% of actual	...	...	*100.00%*	*100.00%*

1.834.010 - CM MAINT OF COMPRESSOR STAT EQUIP - PAYROLL JLC

Actual	0	0	0	269
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*269*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.834.020 - CM MAINTENANCE OF COMPRESSOR STAT EQUIP - MISC ALH

Actual	0	0	0	2,216
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*2,216*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.835.010 - CM MAINT OF MEAS & REG STAT EQUIP - PAYROLL JLC

Actual	0	0	0	648
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*648*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.835.020 - CM MAINTENANCE OF MEAS & REG STAT EQUIP - MISC ALH

Actual	0	0	0	856
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*856*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.837.010 - CM MAINTENANCE OF OTHER EQUIPMENT - PAYROLL JLC

	1994	1995	1996	1997
Actual	0	0	0	84
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*84*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

see attachment no. 2 following the variances

1.837.020 - CM MAINTENANCE OF OTHER EQUIPMENT - MISC ALH

Actual	0	0	0	977
Budget	0	0	0	0
Variance	*0*	*0*	*0*	*977*
% of budget	...	...	...	...
% of actual	...	...	...	*100.00%*

1.856.000 - RIGHT OF WAY CLEARING ALH

Actual	39,661	34,864	41,755	42,458
Budget	45,000	55,000	45,000	45,000
Variance	*-5,339*	*-20,136*	*-3,246*	*-2,542*
% of budget	*-11.86%*	*-36.61%*	*-7.21%*	*-5.65%*
% of actual	*-13.46%*	*-57.76%*	*-7.77%*	*-5.99%*

1994	Wet weather in November - stopped mowing early. Did not resume in the spring.
1995	$22,127.20 - Tranex $34,863.85 - Delta $56,991.05 - Total for 1.856.000 for the year compared to budget of $55,000

1.871.000 - TELEMETRY COSTS ALH

Actual	68,309	51,730	55,996	32,209
Budget	66,000	75,600	48,000	33,600
Variance	*2,309*	*-23,870*	*7,996*	*-1,391*
% of budget	*3.50%*	*-31.57%*	*16.66%*	*-4.14%*
% of actual	*3.38%*	*-46.14%*	*14.28%*	*-4.32%*

1995	There was some planned telemetry that was not constructed. Systems improvements such as use of cell phones and changing long distance carriers provided unscheduled savings. Other reductions in cost came from long distance rate reductions.

	1994	1995	1996	1997

1995	Continued planned savings through service providers did not happen as planned due to coordination problems with various phone companies

1.880.010 - OPERATIONS OFFICE TELEPHONE JLC

	1994	1995	1996	1997
Actual	95,605	90,417	97,284	74,727
Budget	96,000	96,000	87,600	72,000
Variance	*-395*	*-5,583*	*9,684*	*2,727*
% of budget	*-0.41%*	*-5.82%*	*11.05%*	*3.79%*
% of actual	*-0.41%*	*-6.17%*	*9.95%*	*3.65%*

1996	The budget was lowered for anticipated savings due to the installation of a voice/data system. Actual start-up was delayed several months and no savings occurred until the 1996 - 1997 budget year.

1.880.020 - OPERATIONS OFFICE UTILITIES JLC

	1994	1995	1996	1997
Actual	41,643	44,410	46,623	45,279
Budget	44,400	44,400	44,400	46,800
Variance	*-2,757*	*10*	*2,223*	*-1,521*
% of budget	*-6.21%*	*0.02%*	*5.01%*	*-3.25%*
% of actual	*-6.62%*	*0.02%*	*4.77%*	*-3.36%*

1.880.030 - OPERATIONS OFFICE MISC. JLC

	1994	1995	1996	1997
Actual	80,152	74,339	99,763	116,632
Budget	72,000	69,600	80,400	90,000
Variance	*8,152*	*4,739*	*19,363*	*26,632*
% of budget	*11.32%*	*6.81%*	*24.08%*	*29.59%*
% of actual	*10.17%*	*6.37%*	*19.41%*	*22.83%*

1994	The increased level of capitalized items (Budget 1.394) from $300.00 to $500.00 along with costs associated with the opening of new offices in Manchester and Nicholasville were the primary reasons for the increased spending.
1996	Heavy workloads and overtime due to the computer installation along with expansion of the Winchester Warehouse plus remodeling in the Winchester office were the primary reasons for extra costs.
1997	The Primary costs were for Kelly Services Inc. which provided temporary workers for the computer conversion and for routine branch operations. This cost was actually budgeted in the payroll account. Additional costs were associated with items purchased for two construction crews being added to the workforce.

	1994	1995	1996	1997

1.880.040 - FEES TRAINING SCHOOLS JLC

	1994	1995	1996	1997
Actual	68,306	40,477	35,499	49,971
Budget	42,000	47,500	45,600	48,000
Variance	*26,306*	*-7,023*	*-10,101*	*1,971*
% of budget	*62.63%*	*-14.79%*	*-22.15%*	*4.11%*
% of actual	*38.51%*	*-17.35%*	*-28.45%*	*3.94%*

1994	The majority of the budget variance for 1994 was due to computer training that had not been anticipated.
1995 & 1996	Budget variances were a result of our need not being what was anticipated.

1.880.050 - UNIFORMS JLC

	1994	1995	1996	1997
Actual	29,693	36,038	33,807	39,713
Budget	29,000	30,000	34,000	34,000
Variance	*693*	*6,038*	*-193*	*5,713*
% of budget	*2.39%*	*20.13%*	*-0.57%*	*16.80%*
% of actual	*2.33%*	*16.75%*	*-0.57%*	*14.39%*

1995	The budget variance for this year was due to an unexpected price increase and a higher than normal level of uniform replacements.
1997	This budget variance was due to adding two construction crews (10 people) which required the purchase of additional uniforms.

1.880.060 - WELDING SUPPLIES ALH

	1994	1995	1996	1997
Actual	5,707	8,070	8,412	12,650
Budget	4,800	6,000	7,200	7,200
Variance	*907*	*2,070*	*1,212*	*5,450*
% of budget	*18.90%*	*34.50%*	*16.83%*	*75.69%*
% of actual	*15.89%*	*25.65%*	*14.41%*	*43.08%*

1997	Added two Company construction crews in Winchester. The increase represents the costs of two additional welders.

1.881.010 - RENT OPERATING OFFICES JLC

	1994	1995	1996	1997
Actual	15,008	6,758	6,108	6,108
Budget	16,800	10,800	7,200	6,100
Variance	*-1,792*	*-4,042*	*-1,092*	*8*

	1994	1995	1996	1997
% of budget	*-10.67%*	*-37.43%*	*-15.17%*	*0.13%*
% of actual	*-11.94%*	*-59.81%*	*-17.88%*	*0.13%*

1.881.020 - RENT LAND & LAND RIGHTS ALH

Actual	7,216	12,357	11,126	11,177
Budget	11,500	10,200	8,900	9,400
Variance	*-4,284*	*2,157*	*2,226*	*1,777*
% of budget	*-37.25%*	*21.15%*	*25.01%*	*18.90%*
% of actual	*-59.37%*	*17.46%*	*20.01%*	*15.90%*

1.886.000 - MNT STRUCTURES TRANS & DIST. ALH

Actual	51	644	235	345
Budget	1,200	1,200	1,200	800
Variance	*-1,149*	*-556*	*-965*	*-456*
% of budget	*-95.75%*	*-46.33%*	*-80.42%*	*-57.00%*
% of actual	*-2252.94%*	*-86.34%*	*-410.64%*	*-132.17%*

1.887.010 - MNT TRANS & DIST MAINS PAYROLL JLC

Actual	52,391	73,409	91,294	90,894
Budget	0	0	0	0
Variance	*52,391*	*73,409*	*91,294*	*90,894*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.887.020 - MNT TRANS & DIST MAINS OTHER ALH

Actual	43,793	42,330	62,362	72,757
Budget	48,000	39,600	61,200	61,200
Variance	*-4,207*	*2,730*	*1,162*	*11,557*
% of budget	*-8.76%*	*6.89%*	*1.90%*	*18.88%*
% of actual	*-9.61%*	*6.45%*	*1.86%*	*15.88%*

	$6,269 - Cumberland River bank stabilization at Four Mile
1997	$3,020 - Late charges to closed Work Order Number 503-144 expensed to 1.887.020

	1994	1995	1996	1997

1.889.000 - MNT REG STATION TRANS & DIST. ALH

	1994	1995	1996	1997
Actual	4,837	6,819	3,963	3,715
Budget	3,600	6,000	6,000	6,000
Variance	*1,237*	*819*	*-2,037*	*-2,285*
% of budget	*34.36%*	*13.65%*	*-33.95%*	*-38.08%*
% of actual	*25.57%*	*12.01%*	*-51.40%*	*-61.51%*

1.893.010 - MNT OF METERS & REG PAYROLL JLC

	1994	1995	1996	1997
Actual	15,151	15,425	18,131	19,595
Budget	0	0	0	0
Variance	*15,151*	*15,425*	*18,131*	*19,595*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.893.020 - MNT OF METERS & REG OTHER ALH

	1994	1995	1996	1997
Actual	32,817	39,635	39,457	42,850
Budget	36,000	36,000	42,000	42,000
Variance	*-3,183*	*3,635*	*-2,543*	*850*
% of budget	*-8.84%*	*10.10%*	*-6.05%*	*2.02%*
% of actual	*-9.70%*	*9.17%*	*-6.44%*	*1.98%*

1.894.010 - MNT OF OTHER EQUIPMENT PAYROLL JLC

	1994	1995	1996	1997
Actual	14,165	14,210	11,754	17,029
Budget	0	0	0	0
Variance	*14,165*	*14,210*	*11,754*	*17,029*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

see attachment no. 2 following the variances

1.894.020 - MNT OF OTHER EQUIPMENT OTHER ALH

	1994	1995	1996	1997
Actual	73,665	75,085	83,772	65,694
Budget	60,000	64,800	78,000	78,000
Variance	*13,665*	*10,285*	*5,772*	*-12,306*

	1994	1995	1996	1997
% of budget	*22.78%*	*15.87%*	*7.40%*	*-15.78%*
% of actual	*18.55%*	*13.70%*	*6.89%*	*-18.73%*

This account is strictly a historical budget. Expenses are not planned and charges are approved when they are accounted for.

1.898.010 - MNT - TRANSP EQUIP EXPENSE-PAYROLL JLC

Actual	18,605	21,777	24,785	30,899
Budget	40,800	24,000	24,000	26,400
Variance	*-22,195*	*-2,223*	*785*	*4,499*
% of budget	*-54.40%*	*-9.26%*	*3.27%*	*17.04%*
% of actual	*-119.30%*	*-10.21%*	*3.17%*	*14.56%*

1994	Budget overstated, actual is consistent in the years

1.898.020 - MNT - POWER OPR EQUIP EXPENSE-PAYROLL JLC

Actual	11,479	14,223	16,632	18,614
Budget	19,200	16,800	12,000	16,800
Variance	*-7,721*	*-2,577*	*4,632*	*1,814*
% of budget	*-40.21%*	*-15.34%*	*38.60%*	*10.80%*
% of actual	*-67.26%*	*-18.12%*	*27.85%*	*9.75%*

1994	Budget overstated, actual is consistent in the years

1.900.010 - TRANS & DIST. PAYROLL JLC

Actual	1,894,601	1,890,409	1,988,314	2,197,412
Budget	2,486,400	2,534,400	2,626,800	2,699,900
Variance	*-591,799*	*-643,991*	*-638,486*	*-502,488*
% of budget	*-23.80%*	*-25.41%*	*-24.31%*	*-18.61%*
% of actual	*-31.24%*	*-34.07%*	*-32.11%*	*-22.87%*

see attachment no. 2 following the variances

1.900.020 - OPR TRANSPORTATION EXPENSES JLC

Actual	406,570	401,270	408,881	476,746
Budget	348,000	360,000	384,000	398,400
Variance	*58,570*	*41,270*	*24,881*	*78,346*
% of budget	*16.83%*	*11.46%*	*6.48%*	*19.67%*
% of actual	*14.41%*	*10.28%*	*6.09%*	*16.43%*

	1994	1995	1996	1997

1994	Budget was understated.
1995	Budget was understated.
1997	Budget understated. This year we added a new Construction crew which had an effect on the operation and maintenance cost of transportation equipment (1.184.03).
	This account is used in the calculation of determining the transportation rate that we apply to payroll hours charged to operations.

1.900.030 - SMALL TOOLS & WORK EQUIPMENT JLC

	1994	1995	1996	1997
Actual	38,057	44,708	73,437	94,561
Budget	24,000	39,600	39,600	39,600
Variance	*14,057*	*5,108*	*33,837*	*54,961*
% of budget	*58.57%*	*12.90%*	*85.45%*	*138.79%*
% of actual	*36.94%*	*11.43%*	*46.08%*	*58.12%*

1994	Many items began being charged to this account rather then 1.394 (capitalization was raised from $300.00 to $500.00 items). Increased workloads also warranted increased demands for tools and associated items.
1995	The 1995 budget was increased to cover an anticipated need for new and additional tools, however the actual demand was higher than anticipated. The 1995 budget also did not include the extra costs associated with the $300.00 to $500.00 capitalization level.
1996	The workload continued to increase along with personnel, which again surpassed the forecasted demand for work equipment. Several thousand (approx. $15,000) was also for truck tool boxes needed to replace several utility type 1/2 ton trucks that were no longer available. Additional costs of approximately $15,000.00 was to rebuild tapping and stopper equipment for better operational and safety concerns.
1997	Workloads continued to increase, however, the addition of two construction crews was the primary reason for expenditures above the actual budget.

1.903.010 - CASHIERING PAYROLL JLC

	1994	1995	1996	1997
Actual	430,667	446,404	466,090	551,087
Budget	474,600	448,800	470,400	496,600
Variance	*-43,933*	*-2,396*	*-4,310*	*54,487*
% of budget	*-9.26%*	*-0.53%*	*-0.92%*	*10.97%*
% of actual	*-10.20%*	*-0.54%*	*-0.92%*	*9.89%*

1994	Terminations, not replaced
1997	The variance is overtime due to conversion to new system.

	1994	1995	1996	1997

1.903.020 - CUSTOMER COLLECTIONS & RECORDS JFH

	1994	1995	1996	1997
Actual	152,899	168,879	170,951	179,485
Budget	151,200	157,200	164,400	198,000
Variance	*1,699*	*11,679*	*6,551*	*-18,515*
% of budget	*1.12%*	*7.43%*	*3.98%*	*-9.35%*
% of actual	*1.11%*	*6.92%*	*3.83%*	*-10.32%*

1997	Account was over budgeted

1.904.000 - UNCOLLECTIBLE ACCOUNTS JFH

	1994	1995	1996	1997
Actual	100,800	140,800	156,000	220,000
Budget	118,800	100,800	156,000	144,000
Variance	*-18,000*	*40,000*	*0*	*76,000*
% of budget	*-15.15%*	*39.68%*	*0.00%*	*52.78%*
% of actual	*-17.86%*	*28.41%*	*0.00%*	*34.55%*

1994	Based on actual 12/31
1995	2 commercial accounts filed bankruptcy
1997	Increase due to commercial account filing bankruptcy, colder than normal weather and decrease in li-heap funds

1.913.000 - ADVERTISING JLC

	1994	1995	1996	1997
Actual	3,425	14,991	15,884	14,161
Budget	34,200	24,000	24,000	24,000
Variance	*-30,775*	*-9,009*	*-8,116*	*-9,839*
% of budget	*-89.99%*	*-37.54%*	*-33.82%*	*-41.00%*
% of actual	*-898.54%*	*-60.10%*	*-51.10%*	*-69.48%*

Delta in fiscal years 1994, 1995, 1996 and 1997 has attempted to budget an adequate sum of dollars to mount an advertising campaign in several small community newspapers. Due to the competitive nature of the utility market and the large scale multi-media blitz by the electric companies, Delta has made sure additional dollars were available to be more competitive if needed. Advertising has been somewhat limited to one campaign designed to begin in the fall of each year and running through the beginning of the heating season. Delta has for each of these budget years cut our advertising campaigns short to assist our financial position.

1.920.010 - ADMINISTRATIVE PAYROLL JLC

	1994	1995	1996	1997
Actual	1,775,274	1,839,505	1,815,739	1,909,205
Budget	1,681,800	1,737,600	1,706,400	1,720,900

	1994	1995	1996	1997
Variance	*93,474*	*101,905*	*109,339*	*188,305*
% of budget	*5.56%*	*5.86%*	*6.41%*	*10.94%*
% of actual	*5.27%*	*5.54%*	*6.02%*	*9.86%*

1997	Budget classification of certain employees was different than the actual payroll classification, thus the variance.
	Payroll Budget (see attachment 1 (2 sheets) for further payroll acct. #'s)

1.920.020 - ADM TRANSPORTATION EXPENSES JLC

	1994	1995	1996	1997
Actual	90,000	90,000	90,000	90,000
Budget	90,000	90,000	90,000	90,000
Variance	*0*	*0*	*0*	*0*
% of budget	*0.00%*	*0.00%*	*0.00%*	*0.00%*
% of actual	*0.00%*	*0.00%*	*0.00%*	*0.00%*

1.921.010 - ADM TELEPHONE JLC

	1994	1995	1996	1997
Actual	49,266	56,126	102,677	139,280
Budget	48,000	52,800	83,400	132,000
Variance	*1,266*	*3,326*	*19,277*	*7,280*
% of budget	*2.64%*	*6.30%*	*23.11%*	*5.52%*
% of actual	*2.57%*	*5.93%*	*18.77%*	*5.23%*

1996	The budget was increased for anticipated higher costs due to installation of voice/data phone lines. The voice/data system began absorbing some costs that were historically going to budget 1.871 (telemetry costs). Long distance phone costs also increased due to the installation of a new computer system. The actual increase was more than anticipated.

1.921.030 - BOOKS & SUBSCRIPTIONS JFH

	1994	1995	1996	1997
Actual	22,846	23,931	25,457	27,190
Budget	27,600	24,000	27,600	32,700
Variance	*-4,755*	*-69*	*-2,143*	*-5,510*
% of budget	*-17.23%*	*-0.29%*	*-7.76%*	*-16.85%*
% of actual	*-20.81%*	*-0.29%*	*-8.42%*	*-20.26%*

1994	Items budgeted but not purchased
1997	Items budgeted but not purchased

1.921.040 - COMPANY FORMS JLC

	1994	1995	1996	1997
Actual	47,604	42,113	55,450	55,246
Budget	38,400	45,600	45,600	46,800
Variance	*9,204*	*-3,487*	*9,850*	*8,446*
% of budget	*23.97%*	*-7.65%*	*21.60%*	*18.05%*
% of actual	*19.33%*	*-8.28%*	*17.76%*	*15.29%*

1994	Costs associated with customer invoices, envelopes, etc. are the bulk of this budget. Increased paper costs along with increased usage were the primary reasons for the extra expense.
1996	The scheduled start-up of a new computer system was delayed. The invoices, envelopes and other items are not compatible between the two systems. Additional items at lower quantities and higher costs had to be purchased while supplies for the new system was purchased.
1997	The computer system delay and associated costs continued into this budget year. Increased demands due to expanding computer usage and customer base was also a contributing factor.

1.921.050 - SMALL SUPPLY ITEMS JLC

	1994	1995	1996	1997
Actual	52,674	59,979	55,156	85,316
Budget	44,400	48,000	50,400	60,000
Variance	*8,274*	*11,979*	*4,756*	*25,316*
% of budget	*18.64%*	*24.96%*	*9.44%*	*42.19%*
% of actual	*15.71%*	*19.97%*	*8.62%*	*29.67%*

1994 & 1995	Increased usage of PC's, faxes, copiers etc. and associated supplies occurred. The increased capitalization level of account number 1.394 ($300.00 to $500.00) also had an effect along with the opening of two offices.
1997	Costs increased dramatically due to the computer conversion. Printers, PC equipment, etc. had to be installed throughout the company. Unforeseen items and supplies had to be purchased. The 1998 expenditures lowered to $61,085.00. The current budget level is $60,000.00.

1.921.060 - MISCELLANEOUS OTHER ITEMS JLC

	1994	1995	1996	1997
Actual	57,940	60,590	75,769	80,921
Budget	53,800	58,800	72,000	60,000
Variance	*4,140*	*1,790*	*3,769*	*20,921*
% of budget	*7.70%*	*3.04%*	*5.23%*	*34.87%*
% of actual	*7.15%*	*2.95%*	*4.97%*	*25.85%*

	1994	1995	1996	1997

1997	It was anticipated that spending would return to the 1994 and 1995 levels, however the enormous activities and delays associated with the new computer system increased several costs above normal.

1.921.070 - EMPLOYEE MEMBERSHIPS JLC

	1994	1995	1996	1997
Actual	2,735	1,816	3,707	2,159
Budget	3,000	3,000	3,000	3,300
Variance	*-265*	*-1,184*	*707*	*-1,141*
% of budget	*-8.83%*	*-39.47%*	*23.57%*	*-34.58%*
% of actual	*-9.69%*	*-65.20%*	*19.07%*	*-52.85%*

1.921.080 - SAFETY LITERATURE & EDUCATION JLC

	1994	1995	1996	1997
Actual	7,123	16,295	9,630	10,308
Budget	10,800	19,200	10,000	10,000
Variance	*-3,677*	*-2,905*	*-370*	*308*
% of budget	*-34.05%*	*-15.13%*	*-3.70%*	*3.08%*
% of actual	*-51.62%*	*-17.83%*	*-3.84%*	*2.99%*

1.921.090 - ENGR & DRAFTING SUPPLIES ALH

	1994	1995	1996	1997
Actual	8,404	8,175	10,979	11,280
Budget	6,000	9,600	9,600	9,600
Variance	*2,404*	*-1,425*	*1,379*	*1,680*
% of budget	*40.07%*	*-14.84%*	*14.36%*	*17.50%*
% of actual	*28.61%*	*-17.43%*	*12.56%*	*14.89%*

1.921.100 - ADM UTILITIES JLC

	1994	1995	1996	1997
Actual	25,855	26,349	27,167	33,576
Budget	27,600	27,600	26,400	26,400
Variance	*-1,745*	*-1,251*	*767*	*7,176*
% of budget	*-6.32%*	*-4.53%*	*2.91%*	*27.18%*
% of actual	*-6.75%*	*-4.75%*	*2.82%*	*21.37%*

1997	Expansion of the Winchester Warehouse, increased working hours during computer conversion, increased personnel during computer conversion and training and additional air conditioning unit for Data Processing were the primary reasons for the increase.

	1994	1995	1996	1997

1.921.110 - INVENTORY - DIFFERENCE JLC

	1994	1995	1996	1997
Actual	-14,910	3,846	-15,444	-36,023
Budget	0	0	0	0
Variance	*-14,910*	*3,846*	*-15,444*	*-36,023*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

1994	$5,109.00 of the cost was for actual material loss. The remaining sum was for adjustments due to incorrect pricing, receiving errors, etc. The 1994 material activity was $1,258,469.00. $14,910.00 is .01% of that total.
1996	The $15,444.00 was for materials lost on physical inventory counts. 1996 had material activity of $1,524,122.00. $15,444.00 is .01% of the total.
1997	The primary factor in the $36,023.00 sum was an incorrect receipt being transferred to another warehouse ($24,512.44). $24,512.44 was then credited from inventory. 1997 had $1,857.009.00 in material activity. The remaining sum of $11,510.56 is .006% of the activity total.

1.921.210 - TRAVEL ETC CO BUS PRES & CEO GRJ

	1994	1995	1996	1997
Actual	18,346	18,365	16,993	13,569
Budget	20,000	20,000	20,000	20,000
Variance	*-1,654*	*-1,635*	*-3,007*	*-6,431*
% of budget	*-8.27%*	*-8.18%*	*-15.04%*	*-32.16%*
% of actual	*-9.02%*	*-8.90%*	*-17.70%*	*-47.39%*

1996 & 1997	There was less travel than anticipated. Partly this was an effort to curtail in this area due to declining earnings.

1.921.220 - TRAVEL ETC CO BUS OFFICERS GRJ

	1994	1995	1996	1997
Actual	14,347	14,217	15,110	10,603
Budget	12,000	12,000	12,000	15,000
Variance	*2,347*	*2,217*	*3,110*	*-4,397*
% of budget	*19.56%*	*18.48%*	*25.92%*	*-29.31%*
% of actual	*16.36%*	*15.59%*	*20.58%*	*-41.47%*

1.921.230 - TRAVEL ETC CO BUS OPER & CONST ALH

	1994	1995	1996	1997
Actual	30,417	25,786	31,226	26,430
Budget	18,000	30,000	30,000	36,000

	1994	1995	1996	1997
Variance	*12,417*	*-4,214*	*1,226*	*-9,570*
% of budget	*68.98%*	*-14.05%*	*4.09%*	*-26.58%*
% of actual	*40.82%*	*-16.34%*	*3.93%*	*-36.21%*

	This account covers travel, etc. for operations, engineering and construction personnel.
1994	The budget was exceeded by $12,417 (68.98%). During this period, FERC was implementing Order 636 and several trips were involved with the TGP and CGT small customer groups, with the pipelines and with marketers. Also, there were several SGA seminars attended which involved such topics as NGV, construction inspection, gas control, customer service, etc. This budget is usually based upon the prior year's experience plus a margin of 5%. Many of these trips were not anticipated at the time the budget was being prepared.
1997	The budget was underspent by $9,570 (26.58%). Again, this budget was prepared by looking at the prior year's history. Due to poor weather, cost cutting occurred in 1997 which affected costs charged to this budget account.

1.921.240 - TRAVEL ETC CO BUS ADM&CUST SER JLC

Actual	1,030	617	6,430	6,623
Budget	1,200	1,500	8,400	8,400
Variance	*-170*	*-883*	*-1,970*	*-1,777*
% of budget	*-14.17%*	*-58.87%*	*-23.45%*	*-21.15%*
% of actual	*-16.50%*	*-143.11%*	*-30.64%*	*-26.83%*

1.921.250 - TRAVEL ETC CO BUS PUB AFFAIRS RCH

Actual	195	1	1	0
Budget	1,200	1,200	300	1,300
Variance	*-1,005*	*-1,199*	*-299*	*-1,300*
% of budget	*-83.75%*	*-99.92%*	*-99.67%*	*-100.00%*
% of actual	*-515.38%*	*-119900.00%*	*-29900.00%*	...

1.921.260 - TRAVEL ETC CO BUS FINANCE JFH

Actual	1,965	4,453	10,108	7,614
Budget	1,200	1,200	4,900	10,550
Variance	*765*	*3,253*	*5,208*	*-2,936*
% of budget	*63.75%*	*271.08%*	*106.29%*	*-27.83%*
% of actual	*38.93%*	*73.05%*	*51.52%*	*-38.56%*

1996	Variance due to added travel for training due to implementation of new CIS system

	1994	1995	1996	1997

1.921.270 - TRAVEL ETC CO BUS TREASURY JFH

	1994	1995	1996	1997
Actual	2,645	616	0	0
Budget	800	3,000	0	0
Variance	*1,845*	*-2,384*	*0*	*0*
% of budget	*230.63%*	*-79.47%*	...	...
% of actual	*69.75%*	*-387.01%*	...	...

1.921.280 - TRAVEL ETC CO-BUS CUST SERVICE JFH

	1994	1995	1996	1997
Actual	0	6,160	0	0
Budget	0	8,400	0	0
Variance	*0*	*-2,240*	*0*	*0*
% of budget	...	*-26.67%*	...	...
% of actual	...	*-36.36%*	...	...

1.921.290 - CO. BUS. MEALS & ENTERTAINMENT JFH

	1994	1995	1996	1997
Actual	27,776	29,186	32,400	34,113
Budget	24,000	24,000	26,400	30,000
Variance	*3,776*	*5,186*	*6,000*	*4,113*
% of budget	*15.73%*	*21.61%*	*22.73%*	*13.71%*
% of actual	*13.59%*	*17.77%*	*18.52%*	*12.06%*

1995, 1996	Budgets were based on 12/31 actual data and did not include increase in activity or account for inflation

1.922.000 - EXPENSES TRANSFERRED JFH

	1994	1995	1996	1997
Actual	-1,741,171	-1,824,490	-1,870,335	-1,982,502
Budget	-1,645,200	-1,723,200	-1,684,800	-1,776,000
Variance	*-95,971*	*-101,290*	*-185,535*	*-206,502*
% of budget	*5.83%*	*5.88%*	*11.01%*	*11.63%*
% of actual	*5.51%*	*5.55%*	*9.92%*	*10.42%*

	1994	1995	1996	1997

1996 & 1997	This account transfers the applicable Administrative Costs and Field Personnel costs to work orders and subsidiaries. Amounts which are transferred include Administrative payroll and benefits, Other administrative and general costs and Field personnel costs (which include pension, medical, liability insurance, vacation & sick leave and payroll taxes). To the extent that any of these specific accounts are over budget, A/C 922 will be over budget, as has been the case. See separate explanations for the individual fluctuations in those accounts.

1.922.010 - EXPENSES TRANSFERRED (CANADA MOUNTAIN) JFH

	1994	1995	1996	1997
Actual	0	0	-50,094	-902,582
Budget	0	0	0	0
Variance	*0*	*0*	*-50,094*	*-902,582*
% of budget	...	...	...	...
% of actual	...	...	*100.00%*	*100.00%*

1996 & 1997	The 1996 and 1997 budgets had already been finalized by the time the details of the Canada Mountain cost recovery mechanism had been determined. Therefore 1998 was the first budget which included amounts for Canada Mountain.

1.923.010 - OUTSIDE SERVICES LEGAL GRJ

	1994	1995	1996	1997
Actual	73,598	48,102	88,839	89,023
Budget	96,000	96,000	84,000	72,000
% of budget	*130.44%*	*199.58%*	*94.55%*	*80.88%*
% of actual	...	...	...	...

1994 & 1995	We were not required to use all of the budgeted amounts. The spending in this account is affected by changing needs as the year progresses. We were able to restrict our use of outside legal counsel and spend less than budgeted for both these years.
1997	Legal needs required more legal involvement than expected and thus expenses exceeded budget. The budget for this account was reduced in 1997 based partly upon history which had shown some decline in this.

1.923.020 - OUTSIDE SERVICES ACCOUNTING JFH

	1994	1995	1996	1997
Actual	92,400	89,850	100,900	93,514
Budget	64,800	78,000	78,000	80,400
Variance	*27,600*	*11,850*	*22,900*	*13,114*
% of budget	*42.59%*	*15.19%*	*29.36%*	*16.31%*
% of actual	*29.87%*	*13.19%*	*22.70%*	*14.02%*

1994	Budget variance due to unbudgeted consulting for the IRS Revenue Agent Review

	1994	1995	1996	1997

1995	Budget variance due to unbudgeted systems consulting work and tax consulting for the IRS Revenue Agent Review
1996	$20,000 unbudgeted audit fees; $2,900 unbudgeted tax consulting to bring company into compliance with Sec. 263A Capitalized Interest
1997	$7,500 unbudgeted tax consulting (Rev. Proc. 96-31; Software amortization, Form 3115 capitalized interest, depreciation methods for cushion gas); $5,000 unbudgeted audit fee

1.923.030 - OUTSIDE SERVICES JANITORIAL JLC

	1994	1995	1996	1997
Actual	46,481	46,898	49,250	49,549
Budget	46,800	46,800	46,800	50,400
Variance	***-319***	***98***	***2,450***	***-851***
% of budget	***-0.68%***	***0.21%***	***5.24%***	***-1.69%***
% of actual	***-0.69%***	***0.21%***	***4.97%***	***-1.72%***

1.923.040 - OUTSIDE SERVICES OTHER ALH

	1994	1995	1996	1997
Actual	160,145	153,958	151,987	125,859
Budget	140,000	151,000	142,200	163,300
Variance	***20,145***	***2,958***	***9,787***	***-37,441***
% of budget	***14.39%***	***1.96%***	***6.88%***	***-22.93%***
% of actual	***12.58%***	***1.92%***	***6.44%***	***-29.75%***

1994 Actual expenditures exceeded the budget by $20,145 (14.39%). During this fiscal year, FERC required that the interstate pipelines unbundle and become removed from their historical merchant function. Delta incurred above budget expenditures through the Tennessee Gas Pipeline Small Customer Group and the Group's involvement in protecting the interests of Delta, as one of the small customers on the pipeline, and in monitoring the various FERC proceedings that were spawned by FERC Order 636.

1997 Actual expenditures exceeded the budget by $37,441 (22.93%). I am answering these requests without the benefit of having my budget backup before me. I discarded the old material several months ago. However, there are certain charges to account 1.923.040 during this fiscal year which I do not recall having considered when developing the budget. The charges are Jane Hylton Green ($8,400), OrCom Systems ($2,095), and Utility and Economic Consulting ($32,696).

1.923.050 - OUTSIDE SERVICES COMPUTERS JFH

	1994	1995	1996	1997
Actual	0	0	24,619	36,091
Budget	0	0	26,300	41,200
Variance	***0***	***0***	***-1,681***	***-5,109***

	1994	1995	1996	1997
% of budget	...	...	*-6.39%*	*-12.40%*
% of actual	...	...	*-6.83%*	*-14.16%*

1997 Budgeted for extended support Orcom, and six months of support for Data Solutions, Excellent support but installation was not completed therefore these services were not used.

1.924.000 - INSURANCE JFH

Actual	518,507	491,284	484,105	442,478
Budget	539,200	518,900	462,400	446,000
Variance	*-20,693*	*-27,616*	*21,705*	*-3,522*
% of budget	*-3.84%*	*-5.32%*	*4.69%*	*-0.79%*
% of actual	*-3.99%*	*-5.62%*	*4.48%*	*-0.80%*

1.926.010 - TIME OFF PAYROLL JLC

Actual	789,778	417,972	821,978	413,795
Budget	19,000	19,100	18,700	18,600
Variance	*770,778*	*398,872*	*803,278*	*395,195*
% of budget	*4056.73%*	*2088.34%*	*4295.60%*	*2124.70%*
% of actual	*97.59%*	*95.43%*	*97.72%*	*95.51%*

see attachment no. 2 following the variances

1.926.020 - PENSION JLC

Actual	448,286	417,716	332,652	333,254
Budget	400,000	396,000	325,000	366,000
Variance	*48,286*	*21,716*	*7,652*	*-32,746*
% of budget	*12.07%*	*5.48%*	*2.35%*	*-8.95%*
% of actual	*10.77%*	*5.20%*	*2.30%*	*-9.83%*

1994	The variance occurred because projections were made before the actual return on assets and other plan assumptions were known.

1.926.030 - EMPLOYEE 401K PLAN JLC

Actual	106,863	112,379	110,616	151,018
Budget	93,000	109,800	114,000	140,400
Variance	*13,863*	*2,579*	*-3,384*	*10,618*
% of budget	*14.91%*	*2.35%*	*-2.97%*	*7.56%*

	1994	1995	1996	1997
% of actual	*12.97%*	*2.29%*	*-3.06%*	*7.03%*

1994	The variance of $13,863 in this account is due to actual cost being more than the projected budget

1.926.040 - MEDICAL COVERAGE JLC

Actual	713,845	777,283	740,024	664,007
Budget	678,800	728,400	730,000	738,000
Variance	*35,045*	*48,883*	*10,024*	*-73,993*
% of budget	*5.16%*	*6.71%*	*1.37%*	*-10.03%*
% of actual	*4.91%*	*6.29%*	*1.35%*	*-11.14%*

1997	Variance due to Stop Loss Reimbursements & COBRA Reimbursements

1.926.050 - SALARY CONTINUATION COVERAGE JLC

Actual	101,877	82,343	91,676	92,850
Budget	98,400	94,200	108,000	111,600
Variance	*3,477*	*-11,857*	*-16,324*	*-18,750*
% of budget	*3.53%*	*-12.59%*	*-15.11%*	*-16.80%*
% of actual	*3.41%*	*-14.40%*	*-17.81%*	*-20.19%*

1995	Variance due to over projection of cost of salary continuation
1996	Variance due to over projection of cost of salary continuation
1997	Variance due to over projection of cost of salary continuation

1.926.060 - EMPLOYEE STOCK PLAN JLC

Actual	47,653	56,436	50,830	51,565
Budget	48,600	50,400	51,600	52,200
Variance	*-947*	*6,036*	*-770*	*-635*
% of budget	*-1.95%*	*11.98%*	*-1.49%*	*-1.22%*
% of actual	*-1.99%*	*10.70%*	*-1.51%*	*-1.23%*

1995	The balance of account 1.926.060 was incorrectly entered during conversion to new system.

1.926.070 - EMPLOYEE EDUCATION JLC

Actual	4,307	4,284	5,260	1,791
Budget	13,600	5,000	4,000	6,000
Variance	*-9,293*	*-716*	*1,260*	*-4,209*
% of budget	*-68.33%*	*-14.32%*	*31.50%*	*-70.15%*

	1994	1995	1996	1997
% of actual	*-215.77%*	*-16.71%*	*23.95%*	*-235.01%*

1994	Variance due to decline in the number of classes taken by employees

1.926.080 - EMPLOYEE RECREATION & SOCIAL JLC

	1994	1995	1996	1997
Actual	6,277	6,727	3,920	6,477
Budget	8,500	9,500	6,000	6,000
Variance	*-2,223*	*-2,773*	*-2,080*	*477*
% of budget	*-26.15%*	*-29.19%*	*-34.67%*	*7.95%*
% of actual	*-35.42%*	*-41.22%*	*-53.06%*	*7.36%*

1.926.090 - HOUSE TRAILERS JLC

	1994	1995	1996	1997
Actual	2,169	1,713	4,276	1,823
Budget	0	0	0	0
Variance	*2,169*	*1,713*	*4,276*	*1,823*
% of budget	...	...	...	...
% of actual	*100.00%*	*100.00%*	*100.00%*	*100.00%*

1.928.000 - REGULATORY COMMISSION EXPENSE JFH

	1994	1995	1996	1997
Actual	52,158	83,157	68,554	56,584
Budget	50,200	55,100	76,200	70,800
Variance	*1,958*	*28,057*	*-7,646*	*-14,216*
% of budget	*3.90%*	*50.92%*	*-10.03%*	*-20.08%*
% of actual	*3.75%*	*33.74%*	*-11.15%*	*-25.12%*

1995	DOT charges included twice within one year
1996	Over estimated revenues
1997	Timing difference - DOT changed to year end billing

1.930.010 - DIRECTOR FEES & EXPENSES JFH

	1994	1995	1996	1997
Actual	123,971	101,325	107,328	123,200
Budget	88,000	93,000	101,600	98,000
Variance	*35,971*	*8,325*	*5,728*	*25,200*
% of budget	*40.88%*	*8.95%*	*5.64%*	*25.71%*
% of actual	*29.02%*	*8.22%*	*5.34%*	*20.45%*

1994	Variance due to stock and bonuses for directors
1997	Variance due to stock, bonuses and change in compensation schedule for directors

	1994	1995	1996	1997

1.930.020 - COMPANY MEMBERSHIPS JLC

	1994	1995	1996	1997
Actual	77,821	44,909	71,602	45,455
Budget	58,800	82,300	60,000	63,000
Variance	*19,021*	*-37,391*	*11,602*	*-17,545*
% of budget	*32.35%*	*-45.43%*	*19.34%*	*-27.85%*
% of actual	*24.44%*	*-83.26%*	*16.20%*	*-38.60%*

1994	Variance is due to memberships in Gas Associations being greater than was budgeted.
1995	Variance is due to overstated budget based on previous years history and a decrease in membership fees in Gas Associations
1996	Dues paid in 1996 were applicable to 1995, thus the variance.
1997	Variance is due to number of memberships decreasing over previous years history

1.930.030 - FEES CONVENTIONS & MEETINGS JLC

	1994	1995	1996	1997
Actual	4,305	6,463	8,339	4,345
Budget	5,000	6,000	6,000	6,300
Variance	*-695*	*463*	*2,339*	*-1,955*
% of budget	*-13.90%*	*7.72%*	*38.98%*	*-31.03%*
% of actual	*-16.14%*	*7.16%*	*28.05%*	*-44.99%*

1.930.040 • MARKETING JLC

	1994	1995	1996	1997
Actual	43,942	55,308	41,101	36,898
Budget	62,400	64,800	64,800	60,000
Variance	*-18,458*	*-9,492*	*-23,699*	*-23,102*
% of budget	*-29.58%*	*-14.65%*	*-36.57%*	*-38.50%*
% of actual	*-42.01%*	*-17.16%*	*-57.66%*	*-62.61%*

Delta in fiscal years 1994, 1995, 1996 and 1997 has adjusted its marketing expenditures to assist its financial position. Delta's Marketing budget consists primarily of water heater conversion incentives and miscellaneous promotional items. Despite Delta's best efforts, gas water heater conversions have declined thus lessening the projected impact on the overall Marketing budget.

1.930.050 - COMPANY RELATIONS JLC

	1994	1995	1996	1997
Actual	22,582	23,952	29,034	30,987
Budget	30,000	30,000	30,000	31,500

	1994	1995	1996	1997
Variance	*-7,418*	*-6,048*	*-966*	*-513*
% of budget	*-24.73%*	*-20.16%*	*-3.22%*	*-1.63%*
% of actual	*-32.85%*	*-25.25%*	*-3.33%*	*-1.66%*

1994	Over budgeted for various items
1995	Over budgeted for various items

1.930.060 - TRUSTEE, REGISTRAR, AGENT FEES JFH

Actual	52,516	63,772	48,152	46,776
Budget	55,300	57,000	63,200	45,500
Variance	*-2,785*	*6,772*	*-15,048*	*1,276*
% of budget	*-5.04%*	*11.88%*	*-23.81%*	*2.80%*
% of actual	*-5.30%*	*10.62%*	*-31.25%*	*2.73%*

1995	Increase due to fees associated with annual meeting (mailing, printing, etc.)
1996	Decrease due primarily to difference in billing costs from Liberty to Bank One for dividend reinvestment plan

1.930.070 - STOCKHOLDERS MEETINGS JFH

Actual	0	216	0	0
Budget	0	0	0	0
Variance	*0*	*216*	*0*	*0*
% of budget	...	...	...	...
% of actual	...	*100.00%*	...	...

1.930.080 - STOCKHOLDER REPORTS JFH

Actual	54,247	63,183	45,609	39,415
Budget	57,700	57,100	49,500	45,000
Variance	*-3,453*	*6,083*	*-3,891*	*-5,585*
% of budget	*-5.98%*	*10.65%*	*-7.86%*	*-12.41%*
% of actual	*-6.37%*	*9.63%*	*-8.53%*	*-14.17%*

1995	Variance due to NAIC conference participation - not budgeted
1997	Variance due to budgeting NAIC conference - did not participate

1.930.090 - CUSTOMER & PUBLIC INFORMATION RCH

Actual	37,157	36,039	43,432	59,081
Budget	44,400	46,200	46,800	42,000

	1994	1995	1996	1997
Variance	*-7,243*	*-10,161*	*-3,368*	*17,081*
% of budget	*-16.31%*	*-21.99%*	*-7.20%*	*40.67%*
% of actual	*-19.49%*	*-28.19%*	*-7.75%*	*28.91%*

1994	Fiscal year 1994 was $7243 under budget primarily because required informational newspaper advertising was done out of the normal sequence and not paid for in that fiscal year
1995	Fiscal year 1995 was $10,161 under budget due to a mid-year decision to reduce costs and the timing of the purchase of informational materials which are provided to schools and customers.
1997	Fiscal year 1997 was $17,081 over budget because the budgeted amount of $42,000 was unrealistically low considering the history of expenditures, promotion of the Automatic Payment Service, the necessity of including the Lexington Herald- Leader in required newspaper advertising and an increase in the utilization of informational material.

1.930.100 - PUBLIC & COMMUNITY RELATIONS GRJ

Actual	54,969	10,252	52,279	15,815
Budget	18,000	18,000	18,000	20,000
Variance	*36,969*	*-7,748*	*34,279*	*-4,185*
% of budget	*205.38%*	*-43.04%*	*190.44%*	*-20.93%*
% of actual	*67.25%*	*-75.58%*	*65.57%*	*-26.46%*

1994 & 1996	We did more public and community relations than was planned due to needs as they developed in this area.
1995 & 1997	We did less than was expected as needs did not require all of the amounts budgeted.

1.930.110 - CONSERVATION PROGRAM JLC

Actual	39,110	50,875	53,850	55,031
Budget	36,000	48,000	50,000	55,200
Variance	*3,110*	*2,875*	*3,850*	*-169*
% of budget	*8.64%*	*5.99%*	*7.70%*	*-0.31%*
% of actual	*7.95%*	*5.65%*	*7.15%*	*-0.31%*

1.930.120 - LOBBYING EXPENDITURES GRJ

Actual	7,022	0	4,339	0
Budget	0	0	0	0
Variance	*7,022*	*0*	*4,339*	*0*
% of budget	...	...	...	...
% of actual	*100.00%*	...	*100.00%*	...

	1994	1995	1996	1997

1994 & 1996	We budgeted zero for lobbying for 1994 and 1996. The actual expenditures were incurred due to needs to be involved and thus the variances.

1.932.010 - MNT COMMUNICATION EQUIPMENT JLC

	1994	1995	1996	1997
Actual	26,193	30,926	40,261	63,388
Budget	26,400	27,600	30,000	39,000
Variance	*-207*	*3,326*	*10,261*	*24,388*
% of budget	*-0.78%*	*12.05%*	*34.20%*	*62.53%*
% of actual	*-0.79%*	*10.75%*	*25.49%*	*38.47%*

1996	The additional costs for the 1996 variance was primarily due to extensive wind and lightning damage to our radio system and to costs associated with data communication problems between the AS 400 and the Micom voice/data system.
1997	The 1997 costs were primarily a continuation of communication problems between the AS 400 and the Micom voice/data system.

1.932.020 - MNT OFFICE EQUIPMENT JLC

	1994	1995	1996	1997
Actual	53,359	65,911	28,384	19,205
Budget	48,000	60,000	46,800	46,800
Variance	*5,359*	*5,911*	*-18,416*	*-27,595*
% of budget	*11.16%*	*9.85%*	*-39.35%*	*-58.96%*
% of actual	*10.04%*	*8.97%*	*-64.88%*	*-143.69%*

1994	The usage of computers and associated printers increased throughout the company. Additional copiers, faxes, etc, were also being distributed throughout the company. Cost of supplies and maintenance increased accordingly.
1996 & 1997	Budget account number 1.932.05 was created for computer maintenance. The bulk of the office maintenance costs are associated with computers and associated equipment. This budget was not lowered accordingly during 1996 and 1997. This budget is currently $ 30,000.00

1.932.030 - MNT GENERAL STRUCTURES JLC

	1994	1995	1996	1997
Actual	30,805	51,589	28,697	21,811
Budget	30,000	30,000	30,000	30,000
Variance	*805*	*21,589*	*-1,303*	*-8,189*
% of budget	*2.68%*	*71.96%*	*-4.34%*	*-27.30%*
% of actual	*2.61%*	*41.85%*	*-4.54%*	*-37.55%*

	1994	1995	1996	1997

1995	Extensive wiring performed for new computer system and associated electrical back-up generator system in Winchester office.
1997	Although specific projects are normally included in this account historical costs are the basis for the budgeted amount. If the unknown repairs, replacements, etc. do not occur the budget will not be utilized.

1.932.050 - MAINTENANCE COMPUTER EQUIPMENT JFH

	1994	1995	1996	1997
Actual	0	0	50,285	49,418
Budget	0	0	36,000	60,000
Variance	*0*	*0*	*14,285*	*-10,582*
% of budget	...	...	*39.68%*	*-17.64%*
% of actual	...	...	*28.41%*	*-21.41%*

1996	New network installed required extra electrical wiring and hubs for branch offices, that was not included in when the budget was submitted.
1997	Budgeted for outside company to do computer maintenance, but began to use in house personnel for maintenance (David)

Attachment 1

1.409.010 - CURRENT FED INC TAX JFH, Layer 120/141

	1994	1995	1996	1997
Actual	17,700	895,500	-241,100	376,200

1.409.070 - ESTIMATED INTERIM INCOME TAXES JFH, Layer 121/141

	1995	1996	1997
Budget	1,068,500	1,023,500	414,000

1.409.080 - INCOME TAXES NON-REGULATED JFH

	1994	1995	1996	1997
Actual	28,700	32,900	36,200	23900
Budget	0	0	27,400	26300

1.409.020 - CURRENT STATE INC TAX JFH, Layer 122/141

	1994	1995	1996	1997
Actual	36,700	134,700	-315,100	-61,100

1.410.000 - DEFERRED INCOME TAXES JFH, Layer 123/141

	1994	1995	1996	1997
Actual	1,202,700	-248,700	1,814,900	527,700

1.411.000 - INVESTMENT TAX CREDIT NET JFH, Layer 124/141

	1994	1995	1996	1997
Actual	-71,500	-71,400	-71,000	-71,000
Budget	1,014,200	0	0	0

Summary of Tax Accounts

	1994	1995	1996	1997
Actual	1,214,300	743,000	1,223,900	795,700
Budget	1,014,200	1,068,500	1,050,900	440,300
Variance	171,400	-358,400	164,200	357,800
%	16.90%	-33.54%	16.04%	86.43%

Attachment 2

	1994	1995	1996	1997
1.753.01 - Wells & Gathering Payroll	39,908	27,936	22,755	17,904
1.754.01 - Compressor Station Payroll	53,636	53,376	53,160	51,264
1.816.01 - CM Wells Expenses -Payroll				17,036
1.818.01 - CM Compressor Station Expenses-Payroll				15,676
1.926.01 - Time Off Payroll	789,778	417,972	821,978	413,795
1.900.01 - Trans & Dist. Payroll	1,894,601	1,890,409	1,988,314	2,197,412
1.832.01 - CM Maint of Reservoirs and Wells-Payroll				424
1.834.01 - CM Maint of Compressor Stat Equip-Payroll				269
1.835.01 - CM Maint of Meas & Reg Stat Equip-Payroll				648
1.764.01 - Mnt Wells & Gathering Payroll	1,641	232	1,711	2,996
1.765.01 - Mnt Compressor Station Payroll	5,196	3,234	2,146	2,629
1.887.01 - Mnt Trans & Dist Mains Payroll	52,391	73,409	91,294	90,894
1.893.01 - Mnt of Meters & Reg Payroll	15,151	15,425	18,131	19,595
1.894.01 - Mnt of Other Equipment Payroll	14,165	14,210	11,754	17,029
1.837.01 - CM Maintenance of Other Equipment-Payroll				84
1.416.01- Labor Service Expense	10,098	8,433	6,118	5,747
Actual	2,876,565	2,504,636	3,017,361	2,853,402
Budget (1.900.01)	2,486,400	2,534,400	2,626,800	2,699,900
Variance	390,165	(29,764)	390,561	153,502
%	15.69%	-1.17%	14.87%	5.69%

Note: For budget purposes, Delta does not break out the payroll accounts. It combines the Operations and Maintenance accounts under A/C 1.900.01. Therefore, these accounts need to be combined for analysis purposes. The variance for 1994 and 1996 can be explained as follows:

1994 - This is primarily a result of the Bonus paid to Delta's employees.
1996 - This is primarily a result of the Bonus paid to Delta's employees.

Notes

4

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 on the increase in the AAC is largely, if not totally superceded by the Company's ability to recoup any shortfalls through the AAF." Does Delta agree with this conclusion? If not, explain why not?

RESPONSE:

We do not agree with Mr. Catlin's conclusion. Mr. Catlin's statement fails to consider the application of the performance-based cost controls which would place a limitation on the recovery of actual costs. The performance-based cost control measure eliminates the need to limit ***actual*** cost recovery to 5%. Indexing actual costs to CPI-U provides a more effective, more accurate, and more flexible approach for controlling increases in costs than the use of a 5% cap in the determination of the AAF. It is more effective in that it provides an incentive to improve performance at all levels of cost, not just when increases in the AAF exceed 5% of revenue. It is more accurate in that it tracks inflation rather than a fixed percentage amount. It is more flexible in that it provides an incentive even when inflation is running below 5%. Additionally, in the unlikely event that inflation is running above 5%, then the performance-based cost controls would not require Delta to limit increases to 5% even though the CPI-U and increases in Delta's costs might be increasing at a higher rate.

It should also be pointed out that it was never Delta's intention to limit increases in the AAF to 5% of revenue. The combination of increases in costs *and* milder than normal weather could cause the AAF to increase more than 5% of revenue. Since the AAC operates on the basis of weather normalized budgeted costs, and not actual costs, it is more reasonable to limit the AAC to 5% of revenue. The AAF, however, operates as an adjustment against actual costs and therefore could be affected by both increases in costs *and* variations in temperature. Consequently, a 5% limitation on the AAF would have the unintended effect of limiting recoveries related to revenue shortfalls created by milder than normal weather. It was not our intention to place a limitation on the under-collection of revenue requirements due to the impacts of weather.

WITNESS: Steve Seelye

Notes

5

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?

RESPONSE:

We do not agree with Mr. Catlin's conclusion. Mr. Catlin argues that because Delta's non-gas O&M expenses have increased at a rate slightly less than CPI-U during the 5-year period from 1993 through 1998, that Delta has no incentive to decrease costs. Mr. Catlin fails consider that the mechanism provides an incentive for Delta to retain 50% of the O&M savings if it outperforms the CPI-U less the 1.50% deadband. This feature of the mechanism provides a powerful incentive to outperform CPI-U in order to retain 50% of the cost savings. This share of the savings concept 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. (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. 97-171, dated September 30, 1997; and Western Kentucky Gas Company, Case No. 97-513, dated June 1, 1998.)

WITNESS: Steve Seelye

Notes

6

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 mechanisms in place (or penalize performance which is worse than historically achieved). Delta's plan doen not work in this manner." Does Delta agree with this statement? If no, why not?

RESPONSE:

We do not agree with Mr. Catlin's statement. Under Delta's proposal, if Delta's non-gas supply O&M expenses per customer are lower than the ***historical*** non-gas supply O&M expenses approved by the Commission in its most recent rate case, after adjusting for CPI-U, by more than 1.50%, then Delta can retain 50% of the cost savings. If Delta can improve its performance over what has ***historically*** been achieved then it can retain a portion of the cost savings, thus being rewarded for better performance. Once again, Mr. Catlin fails to consider that the mechanism provides an incentive for Delta to retain 50% of the O&M savings if it outperforms the CPI-U less the 1.50% deadband.

WITNESS: Steve Seelye

Notes

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 commercial non-residential firm service, and large non-residential firm service. For each of these, submit Delta's recommendations for the customer charge and base rate.
   (b) How would Delta propose to classify its customers for each service in the two non-residential categories? In other words, what is the distinction between small and large non-residential service?

RESPONSE:

(a) In response to Item 3, part c of the Commission's August 11, 1999 Order, the Company merely stated that it was not opposed to the concept of establishing separate rate schedules for the different classes of customers served under the GS rate schedule. The Company further indicated that, if the Commission favored doing so, it suggested the above three rate schedules for customers currently served under that rate schedule. In that same response, it was also pointed out that the Company believes that the rate design changes proposed in this proceeding do moderate the variability between the class rates of return within the GS rate schedule.

Therefore, at this time, we recommend the same customer charges and base rate Mcf charges proposed by the Company for each rate class if the Commission chooses to establish separate rate schedules. The rates can, however, be simplified with fewer blocks in the residential and small non-residential classes due to the size of the customers served thereunder.

<u>Residential</u>

Inasmuch as all residential usage falls within the first 200 Mcf billing block, we would recommend the following charges:

Customer Charge	$ 8.00 per month
Base Rate per Mcf:	
All Mcf Delivered	$ 3.4787 per Mcf

<u>Small Non-Residential General Service</u>

These customers are small users with most usage falling within the first 200 Mcf billing block. However, since some quantities are billed in the second and third blocks of the General Service Rate, we recommend retaining those blocks as follows:

Customer Charge	$17.00 per month
Base Rate per Mcf:	
First 200 Mcf per month	$ 3.4787 per Mcf
Next 800 Mcf per month	$ 1.8500 per Mcf
Over 1000 Mcf per month	$ 1.4500 per Mcf

<u>Question No. 7</u> (continued)

<u>Large Non-Residential General Service</u>
As pointed out on, beginning on page 10 of my testimony, this class is extremely diverse with respect to size, load factor and rates of return. It is composed of medium size customers with an average load factor that is approximately 18 percentage points lower that the large high-load factor customers within the class (22% versus 40%). The rate of return for the larger customers at the underlying rates was 20.18% as compared to 7.76% for the smaller customers. The rates proposed by the Company in this proceeding address the cost of service differences and bring the rates of return much closer together (13.79% versus 11.99%, respectively). Therefore, we recommend the following charges:

Customer Charge	$50.00 per month
Base Rate per Mcf:	
First 200 Mcf per month	$ 3.4787 per Mcf
Next 800 Mcf per month	$ 1.8500 per Mcf
Next 4000 Mcf per month	$ 1.4500 per Mcf
Next 5000 Mcf per month	$ 1.0500 per Mcf
Over 10000 Mcf per month	$ 0.8500 per Mcf

Another and possibly less complicated alternative would be to establish two rate schedules for the customers currently served under the GS rate schedule, a residential rate and a combined non-residential rate for both small and large customers. The residential rate would be the same as indicated above. The non-residential rate would contain two customer charges (small - $17.00 and large - $50.00). The base Mcf charges for all non-residential customers would be the same as those proposed by the Company in this proceeding and shown above for the Large Non-Residential General Service.

(b) The Company's present and proposed Tariff (Sheet No. 2), distinguishes between the small non-residential and the large non-residential customers based on meter size. Non-residential customers with meters no larger than and AL425 are considered small commercial and pay a lower monthly customer charge. The large non-residential customers have the larger connected loads and require larger metering equipment and pay a higher monthly customer charge. The Company is not proposing to modify the existing method for distinguishing between the two non-residential classes.

WITNESS: Randall Walker