CASE NUMBER:

99-070

Filed 7-30-99

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 40 a and b
Witness: Betty Adams

Data Request:

Refer to the Application, Volume 10 of 10, Tab 8, Schedule H.

a. Explain how the Uncollectible Accounts Expense percentage was determined. Include all supporting workpapers, assumptions, and calculations.

b. Provide a schedule showing Western's actual Uncollectible Accounts Expense percentage for the base year and the five previous fiscal years. Include all supporting workpapers, assumptions, and calculations.

Response:

a. According to the attached schedule we used the most current five year average, rounded.

b. This information is found on the same schedule as the response to a, above. Actual percentage for the base year will not be available until the end of the fiscal year.

Western Kentucky Gas Co
Rate Case 99-070
DR 40 a,b

FYTD GAS SALES(prior yr)	
DOMESTIC	73,314,822
COMMERCIAL	30,353,690
	103,668,512
NET CHARGE OFFS;	
FY 1998 - ACTUAL	706,443
ACTUAL %	0.68%
ACCRUAL %	
FY 1997 - ACTUAL	502,000
ACTUAL %	0.50%
ACCRUAL %	
FY 1996 - ACTUAL	431,000
ACTUAL %	0.44%
ACCRUAL %	
FY 1995 - ACTUAL	171,000
ACTUAL %	0.17%
ACCRUAL %	
FY 1994 - ACTUAL	437,000
ACTUAL %	0.46%
ACCRUAL %	0.30%

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 40 c.
Witness: Rebecca M. Buchanan

Data Request:

40. Refer to the Application, Volume 10 of 10, Tab 8, Schedule H.

c. Explain how the PSC Fees percentage was determined. Include all supporting workpapers, assumptions, and calculations.

Response:

40c.) The PSC Fees percentage of .153919%, shown on Schedule H, is a five year average from 1995 to 1999 of the Tax liability divided by the Revenues. The calculation used to arrive at this percentage is contained below:

Tax Period	Tax Liability	Revenues	Percentage
7/94 – 6/95	$200,928.43	$125,658,807	.1599%
7/95 – 6/96	$200,815.74	$133,078,686	.1509%
7/96 – 6/97	$160,419.87	$128,028,624	.1253%
7/97 – 6/98	$230,394.32	$156,517,883	.1472%
7/98 – 6/99	$276,351.00	$151,176,695	.1828%
	$1,068,909.36	$694,460,695	**.1539%**

(Source: figures provided by Western Controller).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 41
Witness: Rebecca M. Buchanan

Data Request:

41. Refer to the Application, Volume 10 of 10, Tab 8, Schedule I-1. In light of the revenue increase requested by Western, explain why Schedule I-1 shows Western is forecasted to experience net losses beginning in fiscal year 2001.

Response:

41.) Western's forecasted revenues were calculated using the currently approved rates. Schedule I-1 demonstrates that without rate relief, Western will experience net losses beginning in fiscal year 2001. In fact, without rate relief, and considering the ratemaking adjustments shown in Schedule C-2 ,Vol. 10, Tab 3, Western will experience net losses after taxes and interest in the Forecasted Test Year.

(Note: In some copies of the filing, Schedule "I" was placed under the wrong tab. All Schedules "I" should be under Tab 9. The Company apologizes for any confusion that this may have caused).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 42 a., b., c., and d.
Witness: Rebecca M. Buchanan

Data Request:

42. Refer to the Application, Volume 10 of 10, Tab 15, Summary of Factors schedule, referenced as "WP Factors." Concerning the calculation of the Residual Factor:

a. Explain why the Residual Factor is based on calendar year 1998 data.

b. Provide the Residual Factors for all other Atmos utility and non-utility business divisions.

c. Explain why it is reasonable to base the Residual Factor on the Western to Atmos ratios for Gross Direct PP&E, Average Number of Customers, and Total O&M Expense.

d. Explain the reference to the "Gray Book."

Response:

42a.) Barring a major shift in the structure of Atmos, there will be little change in the residual factor from year to year. For ratemaking purposes, the residual factor was updated to a period within the base year. At the time the calculation was made, twelve months ended December 31, 1998 was the period for which the data was most readily available. Had the calculation been made on a different 12 month period within the base year, the change in the residual factor would be minimal.

42b.) See the attached schedule titled "Attachment #1 – Fiscal 1998 Computation of Allocation Factors (Including UCG) - Atmos Energy Corporation" and marked "response to DR 42b." These are the residual factors actually used by the Atmos Accounting department for fiscal year 1998 allocations. The residual factor for Western on the attachment (column headed "WKG" with a factor of 16.53% circled) differs slightly from the factor used in the filing. (As explained in 42a above, the residual factor for Western was updated for purposes of the rate case to 16.657%).

42c.) The residual factor used by Atmos is a modified Massachusetts formula. It is used to allocate the General Plant related items (plant and accumulated depreciation) of Division 02 General Office to the business units of Atmos. The three part allocator alleviates the inequities that can occur if only one of the components is used as an allocator. Gross plant, average customers and O&M expenses are a better reflection of the types of functions provided by the General Office (also known as Shared Services). The General Plant assets of Division 02 are used in conjunction with providing these "shared services" to the business units. (Some examples of the functions performed by the General Office Division 02 are Gas Control, Billing & Remittance, and Investor Relations. A complete listing of the Shared Services functions is provided in FR 10(9)(u), Volume 9, tab 2).

For an extensive discussion of allocations and the use of a residual factor, please refer to the direct testimony of Mr. Arthur L. Litke who testified on behalf of Western Kentucky Gas Company in Case No. 90-013.

42d.) The term "Gray Book" refers to the financial reports that are distributed internally (the managerial reports). In years past, the cover on the report was gray in color. Western's "Gray Book" is provided in the filing as FR10(9)(n) in Volumes 5, 6, and 7.

response to DR 42b

Attachment #1 - Fiscal 1998 Computation of Allocation Factors (Including UCG)

ATMOS ENERGY CORPORATION

		Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	UCG Energy	UCG Storage	WKGR
Total Residual Factor													
R:9 Gross Direct PP&E	%	100.00%	21.07%	11.34%	9.43%	42.28%	15.75%	0.00%	0.00%	0.08%	0.00%	0.00%	0.05%
R:10 Average Number of Customers	%	100.00%	29.76%	11.14%	7.99%	32.99%	17.41%	0.08%	0.62%	0.01%	0.00%	0.00%	0.00%
R:11 Total O&M Exp. (August 15 - Budget '98)	%	100.00%	23.30%	13.60%	7.82%	38.25%	16.44%	0.13%	0.32%	0.12%	0.00%	0.00%	0.02%
R:12 Total Residual Factor	%	100.00%	24.72%	12.03%	8.41%	37.84%	$\boxed{16.53\%}$	0.07%	0.31%	0.07%	0.00%	0.00%	0.02%
Regulated Only Residual Factor													
R:13 Gross Direct PP&E	%	100.00%	21.11%	11.35%	9.44%	42.33%	15.77%						
R:14 Average Number of Customers	%	100.00%	29.96%	11.22%	8.05%	33.23%	17.54%						
R:15 Total O&M Exp. (August 15 - Budget '98)	%	100.00%	23.44%	13.68%	7.86%	38.48%	16.54%						
R:16 Regulated Only Residual Factor	%	100.00%	24.84%	12.08%	8.45%	38.01%	16.62%						

43

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 43 a. – e.
Witness: Rebecca M. Buchanan

Data Request:

43. Refer to the Application, Volume 10 of 10, Tab 15, WP B-2, base period for Division 09, pages 3 and 4 of 4. For each of the column headings listed below, identify the source of information for the items contained in the column and provide the cross-reference to where that item can be found in the Application. If the item has not been provided in the Application, provide the source of information for the item in question.

a. "WKG Direct Additions FY 99."
b. "service prog. WKG adds April 1999."
c. "WKG OH 98 carryover."
d. "WKG OH FY 99."
e. "02 OH FY 99."

Response:

43 a, d, e.) The source for "WKG Direct Additions FY 99," "WKG OH FY 99," and "02 OH FY 99" is Volume 3 of 10, tab 1, exhibit DHD-1, page 1 of 6.

43b.) The source for "service prog. WKG adds April 1999" is the attached worksheet titled "Service Programs Investment Closed April 1999 – Western Kentucky Gas Company" and marked "response to DR 43b."

As explained in response to DR 35a, there is a final column on page 4 of WP B-2 B09 that was unintentionally excluded from the print range in the original filing. The column is headed "service program additional". (A copy of this workpaper page including the final column has been provided in response to DR 35a, and for convenience it is attached to this response as well). The source of the amount in this final column titled "service program additional", $2,632,460, is the same source document as the April 1999 service program investments referenced above and attached. The $2,632,460 is the estimated cost to complete the Service Programs, and will be closed between May and September 1999. Together, these two columns total $21,868,300 and make up the service program investment forecast for fiscal year 1999. This topic is discussed in the direct testimony of Mr. Conrad E. Gruber, found in Volume 2, tab 1, page 15 of the filing.

43c.) At fiscal year end 1998, there remained a balance in the Western's overhead account 1070 to be applied to the 1999 capital expenditures. During fiscal year 1999, as direct capital expenditures are closed to plant, an additional 16% of overhead is applied in order to draw down the remaining 1998 balance. The column headed "WKG OH 98 carryover" is Western's budget for the 16% overhead clearing. The budgeted percent and amount has been verified by Western's Controller.

Service Programs Investment Closed April 1999
Western Kentucky Gas Company

response to DR 43b

				Depreciation	
			Rate *	Half Year	Full Year
390.000	Leasehold Improvements	$ 134,459	2.12	$ 1,425	$ 2,851
391.000	Office Furniture	283,245	7.05	9,984	19,969
397.000	Communications Equip-Telepho	282,328	5.21	7,355	14,709
399.060	PC Hardware	2,263,318	18.51	209,470	418,940
399.070	PC Software	103,668	15.85	8,216	16,431
399.080	Application Software	9,215,475	12.50	575,967	1,151,934
39xxx1	Server Hardware	695,971	14.29	49,727	99,454
39xxx2	Server Software	228,311	14.29	16,313	32,626
39xxx3	Network Cost	332,234	14.29	23,738	47,476
39xxx4	Start Up Cost	5,696,831	8.33	237,368	474,736
		$ 19,235,840		$ 1,139,563	$ 2,279,127

Note: The remaining cost to complete the Service Programs is estimated to be $2.632mm, and will be closed between May and Sept. 1999. The remaining costs are all considered to be Banner-related Application Software.

* Depreciation Rates are from the latest Deloitte Touche Study.

Source: sheet provided by Atmos Plant Accounting Manager.

Western Kentucky Gas Company
Computation of 13 Month Average Plant Balances - Western Div. 09
workpaper WP B-2 B 09
Base Period 10/1/98 - 9/30/99

Line No.	Acct. No.	Account Title	WKG Div 09 Plant Balance Sep-99	WKG Direct Additions FY 99	service prog. WKG adds April 1999	WKG OH 98 carryover	WKG OH FY 99	02 OH FY 99	service program additional
			Projected	Budgeted		16.000%	33.692%	20.250%	
48		Distribution Plant							
49	374.10	Land Town Border	61,710			0	0	0	
50	374.30	Land Other	2,784			0	0	0	
51	374.20	Right of Way	44,872			0	0	0	
52	375.10	Structures & Improvements T.B.	106,376			0	0	0	
53	375.02	Structures & Improvements Other	0			0	0	0	
54	375.03	Improvements	7,518			0	0	0	
55	375.20	Land Rights	46,591			0	0	0	
56	376.00	Mains	71,878,855	1,946,304		311,409	655,751	394,121	
57	378.10	Meas. & Reg. Sta. Equipment General	2,137,306	150,490		24,078	50,703	30,474	
58	379.30	Meas & Reg. Sta. Equipment T.b.	1,803,835	90,002		14,400	30,324	18,225	
59	380.00	Services	43,729,545	1,914,168		306,267	644,924	387,614	
60	381.00	meters	18,839,620	488,201		78,112	164,485	98,859	
61	381.20	V & P Guages	109,524			0	0	0	
62	382.00	Meter Installations	14,004,066	474,696		75,951	159,935	96,125	
63	383.00	Regulators Service	3,610,207	106,634		17,061	35,927	21,593	
64	383.20	Regulators Relief	481,545			0	0	0	
65	384.00	House Reg. Installations	163,793	2,250		360	758	456	
66	385.10	Ind. Meas. & Reg. Sta. Equipment	3,058,017	74,400		11,904	25,067	15,066	
67									
68		Total Distribution Plant	160,086,162	5,247,145		839,543	1,767,875	1,062,533	
69									
70		General Plant							
71	389.10	Land	44,728			0	0	0	
72	390.02	Structures & Improvements	316,621		134,459	0	0	0	
73	390.03	Improvements	64,111			0	0	0	
74	390.04	Air Conditioning Equipment	9,771			0	0	0	
75	390.05	Total Energy	0			0	0	0	
76	390.09	Improvement to leased Premises	1,394,282	10,001		1,600	3,370	2,025	
77	391.00	Office Furniture & Equipment	1,861,880	1,500	283,245	240	505	304	
78	391.83	Office Machines	200,479			0	0	0	
79	392.10	Transportation Equipment	6,044,074			0	0	0	
80	392.20	Trailers	165,970			0	0	0	
81	n/a	n/a	0			0	0	0	
82	394.77	Tools & Work Equipment	3,070,937	4,000		640	1,348	810	
83	396.93	Ditchers	853,615			0	0	0	
84	396.94	Backhoes	706,023			0	0	0	
85	396.95	Welders	92,413			0	0	0	
86	397.00	Communication Equipment - Phones	1,100,364	40,000	282,328	6,400	13,477	8,100	
87	397.20	Communication Equip. - Fixed Radios	21,697			0	0	0	
88	397.21	Communication Equipment - Mobile Radios	68,220	6,000		960	2,022	1,215	
89	397.22	Communication Equip. - Telemetering	114,695			0	0	0	
90	398.00	Miscellaneous Equipment	37,073			0	0	0	
91	399.00	Other Tangible Property	0			0	0	0	
92	399.84	Other Tangible Property - CPU	0			0	0	0	
93	399.85	Other Tangible Property - MF Hardware	397,278			0	0	0	
94	399.86	Other Tangible Property - PC Hardware	2,828,889	35,980	2,263,318	5,757	12,122	7,286	
95	399.87	Other Tang. Property - P.C. Software	306,173	10,000	103,668	1,600	3,369	2,025	
96	399.88	Other Tang. Property - Application Software	12,054,929		9,215,475	0	0	0	2,632,460
97	399.89	Other Tang. Property - System Software	0			0	0	0	
98	39x.xx1	Server Hardware	695,971		695,971				
99	39x.xx2	Server Software	228,311		228,311				
100	39x.xx3	Network Cost	332,234		332,234				
101	39x.xx4	Start Up Cost	5,696,831		5,696,831				
102	999.00	Cushion Gas	1,694,833			0	0	0	
103									
104		Total General Plant	40,402,400	107,481	19,235,840	17,197	36,213	21,765	2,632,460
105									
106		Total Gas Plant in Service	229,322,800	5,461,802	19,235,840	873,888	1,840,198	1,106,000	2,632,460

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 44 a. – d.
Witness: Rebecca M. Buchanan

Data Request:

44. Refer to the Application, Volume 10 of 10, Tab 15, WP B-2, forecasted period for Division 09, pages 3 and 4 of 4. For each of the column headings listed below, identify the source of information for the items contained in the column and provide the cross-reference to where that item can be found in the Application. If the item has not been provided in the Application, provide the source of information for the item in question.

a. "WKG Direct Additions FY2000."

b. "WKG OH FY2000."

c. "02 OH FY2000."

d. "WKG Additions FY2001."

Response:

44 a, b, c.) The source for "WKG Direct Additions FY2000," "WKG OH FY2000," and "02 OH FY2000" is Volume 3 of 10, tab 1, exhibit DHD-1, page 2 of 6. (Note: The test year includes 9/12 of these additions, because the test year is made up of 9/12 of fiscal year 2000).

44d.) The source for "WKG Additions FY2001" is Volume 3 of 10, tab 1, exhibit DHD-1, page 4 of 6. (Note: The test year includes 3/12 of these additions, because the test year is made up of 3/12 of fiscal year 2001).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 45 a. – e.
Witness: Rebecca M. Buchanan

Data Request:

45. Refer to the Application, Volume 10 of 10, Tab 15, WP B-3.2, for both the base and forecasted periods, Division 09.

a. For the base period, explain the reason for the columns titled "Total Company Adjusted Jurisdiction – Reserve" and "Reserve Computation."

b. For the forecasted period, explain the reason for the columns titled "Division 09 13 Month Avg. – Reserve" and "Reserve Computation."

c. For both periods, explain why the "12 Month Expense" column includes a reference to 95.45 percent.

d. Provide the calculations used to determine the 95.45 percent.

e. For the forecasted period, explain the reference to "ELG" in the annual accrual rate column.

Response:

45a.) The Company apologizes for any confusion caused by the column titles. For the base period workpaper WP B-3.2, the dollar amounts in the column titled "Total Company Adjusted Jurisdiction – Reserve" are the Western Division 09 13-month-average base period accumulated reserve balances. This column is for display purposes only. The source is Schedule WP B-3.1 B 09, pages 1 and 2.

The dollar amounts in the column titled "Reserve Computation" are the annual reserve accruals. The reserve accrual is calculated by multiplying the 13-month-average investment (column D) by the Annual Accrual Rate (column G).

45b.) For the forecasted period workpaper WP B-3.2, the dollar amounts in the column titled "DIVISION 09, 13 Month Avg. – Reserve" are the Western Division 09 13-month-average forecast period accumulated reserve balances. This column is for display purposes only. The source is WP B-3.1 F 09, pages 1 and 2.

The dollar amounts in the column titled "Reserve Computation" are the annual reserve accruals. The reserve accrual is the 13-month-average investment (column D) multiplied by the Annual Accrual Rate (column G).

45c.) For depreciation expense, certain items are recapitalized. Column F on workpaper WP B-3.2 B 09 and F 09 shows that on average, 95.45% of the Division 09 annual reserve computation will be expensed.

45d.) The 95.45% Division 09 expense factor was calculated as follows: 12 months depreciation and amortization expense per book at September 1998 \$6,486,839 divided by 12 months of Provision for depreciation and amortization per book as of September 1998 \$6,796,268.

45e.) For the forecasted period, the reference to "ELG" in the annual accrual rate column of WP B-3.2 refers to the depreciation rates from the latest depreciation study by Deloitte Touche. This study can be found in Volume 8, tab 4. According to the Deloitte Touche study, ELG means "equal life group".

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 46
Witness: Betty Adams

Data Request:

Refer to the Application, Volume 10 of 10, Tab 15, WP B-4.1, Working Capital Components, for both base and forecasted periods. Provide a breakdown showing all accounts and subaccounts contained in the Prepayments for each period. This breakdown should use the same accounting system as was used to show the detail for Materials and Supplies.

Response:

Attached is the breakdown by account and subaccount of the Prepayments contained within WP B-4.1.

Base Year

DR 46
Schedule A
Page 1 of 2

Account	Description	actual Sep-98	actual Oct-98	actual Nov-98	actual Dec-98	actual Jan-99	actual Feb-99	actual Mar-99	budget Apr-99	budget May-99	budget Jun-99	budget Jul-99	budget Aug-99	budget Sep-99	13 month average
Prepayments															
Div 09															
166010101	Workers Comp	-	-	-	-	-	-		-	-	-	9,713	9,713	3,035	
166010102	Property Ins	18,313	20,592	17,888	26,641	22,895	19,149	15,403	3,283	-	27,606	25,095	22,587	20,077	
166010103	Auto Liability	-	-	-	-	-	(6,935)	(6,935)	-	-	(5,900)	(4,618)	(681)	-	
166010113	Liability Ins	1,787	893	-	-	-	-		81,615	65,470	49,326	36,727	20,583	4,439	
166010123	Amer Ins Co	-	40,639	36,945	33,250	29,556	25,861	22,167	31,793	24,716	17,639	14,154	7,077	-	
166010133	AEGIS Off & Dir Liab	42,925	110,143	177,360	88,679	77,947	67,214	56,482	21,358	20,588	22,690	51,617	45,168	51,436	
166040401	Gilliland Rent I						52,646	52,646	-	-	-	-	-	-	
166040402	Gilliland Rent II						3,719	3,719	-	-	-	-	-	-	
166070301	PSC Assessment	96,977	86,202	75,427	64,652	(42,677)	159,898	132,078	104,258	76,438	48,618	195,436	174,512	153,588	
166070504	Alliance Gas	-	-	-	-	-	-		14,052	71,322	26,735	-	25,581	(31,534)	
166070505	Tenn Alliance Gas	-	-	-	-	-	-		32,781	135,218	62,371	-	59,678	(73,565)	
		160,002	258,469	307,620	213,222	87,721	321,552	275,560	289,140	393,752	249,085	328,124	364,218	127,476	259,688
Div 02															
166010101	Workers Comp			(28,955)	838				-						
166010102	Property Ins								2,370						
166010113	Liability Ins						(3,821)		-						
166030102	SEBP Ins	543,381	485,287	425,986	366,684	307,383	248,081	188,780	393,486	508,977	449,675	390,373	331,072	543,381	
166040101	Postage	(8,307)	(1,328)	(6,701)	(15,905)	(11,989)	(29,114)	(19,951)	6,768	8,038	9,794	3,863	11,075	11,417	
166040102	Inserter	10,619	(7,946)	17,913	15,501	(85,862)	86,050	(17,497)	19,698	8,122	(26,038)	21,894	66,064	20,970	
166040103	Mail box	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	
166040104	Business reply	3,299	3,186	2,466	3,404	3,241	3,241	3,213	3,375	3,328	3,305	3,263	3,214	3,172	
166040105	Postage due	72	61	53	52	13	(230)	(266)	372	371	370	345	323	322	
166040106	Lincoln Center mail room	44	44	44	44	44	44	44	44	44	44	44	44	44	
166070001	CIS Project	425,845	425,845	371,720	344,658	471,769	444,707	417,644	479,975	505,693	508,731	487,564	547,668	497,053	
166070002	Oracle Database Maint	121,261	121,261	108,778	102,536	96,295	80,270	80,246	185,904	180,108	174,313	168,517	165,842	156,926	
166070004	Monster Board-Internet						3,500		-	-	-	-	-	-	
166070005	Amer Gas Cooling Ctr						18,180	16,362	-	-	-	-	-	-	
166070201	Southern Gas Assoc	4,001	2,667	1,334		(1,334)	(2,668)	11,099	10,667	9,334	8,000	6,667	5,334	4,001	
166070202	American Gas Assoc	65,287	43,525	21,763	21,762	21,762	21,762	65,287	22,362	11,249	1,102	(10,147)	368	32,644	
166070501	Nation Bank of Texas	58,333	52,500	46,667	40,833	35,000	29,167	23,333	15,834	11,875	7,917	3,959	62,084	56,667	
166070502	Int of Gas Tech	3,162	42,108	41,054	40,000	35,556	49,291	44,362	10,541	8,433	6,325	4,217	6,324	4,743	
		1,226,424	1,167,137	1,002,049	920,334	871,805	948,387	812,583	1,151,323	1,255,499	1,143,465	1,080,486	1,199,339	1,331,267	
Total	(only 16.657% of Div 02)	364,287	452,879	474,531	366,522	232,938	479,525	410,912	480,916	602,880	439,552	508,101	563,992	349,225	440,482

Forecasted Year

Account	Description	budget Dec-99	budget Jan-00	budget Feb-00	budget Mar-00	budget Apr-00	budget May-00	budget Jun-00	budget Jul-00	budget Aug-00	budget Sep-00	budget Oct-00	budget Nov-00	budget Dec-00	13 month average
Prepayments															
Div 09															
166010101	Workers Comp	-	19,250	-	-	-	-	-	-	-		-	-	-	
166010102	Property Ins	26,584	24,168	21,752	19,336	16,920	14,504	12,088	9,672	7,256	4,840	2,424	29,000	26,584	
166010103	Auto Liability	-	(6,000)	-	-	-	(6,000)	-	(5,900)	(6,169)		-	-	-	
166010113	Liability Ins	82,500	75,000	67,500	60,000	52,500	45,000	37,500	30,000	22,500	15,000	7,500	9,000	82,500	
166010123	Amer Ins Co	73,334	66,668	60,002	53,336	46,670	40,004	33,338	26,672	20,006	13,340	6,674	80,000	73,334	
166010133	AEGIS Off & Dir Liab	100,834	91,668	82,502	73,336	64,170	55,004	45,838	36,672	27,506	18,340	9,174	100,834	91,668	
166040401	Gilliland Rent I				-	-	-	-	-	-					
166040402	Gilliland Rent II				-	-	-	-	-	-					
166070301	PSC Assessment	90,816	69,892	55,913	41,934	27,955	13,976	155,833	141,666	127,499	113,332	99,165	84,998	70,831	
166070504	Alliance Gas	(19,934)	(38,227)	(59,984)	-	50,208	30,859	32,751	-	41,322	99,445	11,583	(13,609)	(11,189)	
166070505	Tenn Alliance Gas	(46,514)	(89,197)	(139,964)	17,245	81,814	95,793	76,404	10,303	88,204	201,594	23,482	(31,754)	(26,108)	
		307,620	213,222	87,721	265,187	340,237	289,140	393,752	249,085	328,124	465,891	160,002	258,469	307,620	282,005
Div 02															
166010101	Workers Comp	-	838				-								
166010102	Property Ins						2,370								
166010113	Liability Ins						-								
166030102	SEBP Ins	365,476	307,383	246,873	186,363	393,486	508,977	449,675	449,675	390,373	543,381	485,287	425,986	366,684	
166040101	Postage	(6,701)	(15,905)	(11,989)	8,011	13,011	22,000	8,038	9,794	3,863	3,863	3,863	3,863	3,863	
166040102	Inserter	55,000	45,000	(45,000)	26,649	22,884	19,698	64,855	(7,500)	6,870	(15,500)	17,573	21,894	21,894	
166040103	Mail box	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	
166040104	Business reply	2,466	3,404	3,241	3,241	3,241	3,375	3,328	3,305	3,263	3,263	3,263	3,263	3,263	
166040105	Postage due	53	52	13	13	13	372	371	370	345	345	345	345	345	
166040106	Lincoln Center mail room	44	44	44	44	44	44	44	44	44	44	44	44	44	
166070001	CIS Project	430,339	376,797	471,769	579,948	415,624	382,558	505,693	489,481	453,729	384,584	487,564	472,514	418,029	
166070002	Oracle Database Maint	108,778	102,536	115,926	118,376	84,834	148,172	180,108	174,313	168,517	132,923	168,517	168,517	144,483	
166070004	Monster Board-Internet						-	-	-	-	-	-	-	-	
166070005	Amer Gas Cooling Ctr						-	-	-	-	-	-	-	-	
166070201	Southern Gas Assoc	-	14,663	13,330	11,997	10,664	9,331	7,998	6,665	5,332	3,999	2,666	1,333	-	
166070202	American Gas Assoc	-	21,762	21,762	21,762	21,762	22,362	11,249	1,102	(10,147)	4,853	14,853	34,853	16,853	
166070501	Nation Bank of Texas	46,667	40,833	34,999	29,165	23,331	17,497	11,663	5,829	50,000	44,166	38,332	32,498	26,664	
166070502	Int of Gas Tech	-	23,000	20,910	18,820	16,730	14,640	12,550	10,460	8,370	6,280	4,190	2,100	-	
		1,002,049	920,334	871,805	1,004,316	1,005,551	1,151,323	1,255,499	1,143,465	1,080,486	1,112,128	1,226,424	1,167,137	1,002,049	
Total	(only 16.657% of Div 02)	474,531	366,522	232,938	432,476	507,732	480,916	602,880	439,552	508,101	651,138	364,287	452,879	474,531	460,653

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, a
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

a. Provide the name of the model used for the cost-of-service study and specify whether this is an industry model or an in-house model. Provide a narrative description of the study and written operating procedures for running the model.

Response:

The class-cost-of-service study filed in this case was developed in-house on an Excel spreadsheet. It is generally referred to as the Western Kentucky Gas Class Cost of Service Study. The study is an embedded cost of service study which allocates total costs among customer classes in a manner consistent with the incurrence of those costs. The resulting class rates of return are shown on page 1 of the study. The study is conducted by first functionalizing costs as production, transmission, distribution, storage or gas cost. The functionalization of rate base is shown on page 3 of the study with support presented on sheet 1 attached to the study. Then the functionalized costs are classified as customer, demand, commodity or direct. The classifications are shown on pages 4, 6, 8, 10, 12 and 14 of the study with support presented on sheet 2 attached to the study. The classified costs are then allocated among customer classes. Rate class comparisons are shown on page 2 of the study. The allocations are shown on pages 5, 7, 9, 11, 13 and 15 of the study. The allocation factors are derived on pages 16 and 17 of the study. Billing data for each of the customer classes is presented on page 18 of the study. Page 19 shows allocated customer costs for each of the classes. Other data inputs are shown on sheets 3, 4, 6, 7, 8, and 9 attached to the study. Sheet 5 summarizes classified and allocated amounts. The study is in a standard Excel workbook and does not contain any macros. No special operating procedures are required for running the model.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, b
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

b. Do any of Western's affiliates use this model? If so, identify any concerns that have been expressed or modifications that have been made other state regulatory commissions in cases in which this model has been presented in support of those affiliates' revenue allocation or rate design proposals.

Responses:

None of Western's (Atmos Energy Corporation dba Western Kentucky Gas in Kentucky) affiliates are regulated public utilities. Therefore, they would not use a model that allocates a utility cost-of-service among classes of utility customers. The other business units of Atmos which are regulated as public utilities are not separate corporate entities. The business units are described in the response to Data Request 2. Atmos Energy Corporation dba Greeley Gas Company in Colorado filed a similar class cost of service study in docket no. 95S-146G. That case was settled in September 1995. The settlement agreement did not specify any concerns or modifications regarding the class cost-of-service study. None of the other Atmos business units currently utilize this model.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, c
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

c. Identify any other models that were considered by Western prior to selecting this model and whether the other models provided similar results and guidance. If other models were reviewed, why was this model considered superior? If no other models were reviewed, how can the Commission be assured that the guidance represented by this model is the most reasonable?

Response:

Western first filed a class cost-of-service study with this commission using a form of the model filed in this case in Case no. 9556 in 1986. In its next case, no. 90-013, Western filed a class cost-of-service study that was based on the study from case no. 9556 with modifications to address the Commissions comments about the study in the final order in case no. 9556. In its next case, no. 95-010, Western again filed a class cost-of-service study using the model from the prior studies with further modifications to address the Commissions comments about the study in case no. 90-013. Thus, the model has evolved over the last 13 years to reflect the Commission's input. In this case Western again filed a class cost-of-service study based on the prior studies with limited modifications as disclosed in Mr. Petersen's testimony. Since the Company had available a class cost-of-service study model that had been presented to the Commission in three prior cases and had been modified to address the Commission's comments in those cases, the Company did not believe a search for an alternative model was necessary and therefore no other models were reviewed.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, d
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

d. Class load factor is defined by Mr. Petersen as the average daily use divided by design day use or maximum daily contract level. Expand on this definition and explain how this factor is used in the model.

Response:

Class load factor is calculated on page 2 of the class cost of service study as average daily use per class (annual volume from line 2 of page 16 divided by 365 days) divided by total design day use per class from line 20 of page 16. Design day use on line 20 of page 16 includes the maximum daily contract level for customers who have such contracts. The class load factor is not used in any of the cost allocators in the study. It is shown on page 2 of the study as part of a comparison of differences in load characteristics among the five rate classes used in the study.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, e
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

e. On page 3 of his testimony Mr. Petersen states that the rate classes selected use available data that captures the class differences in load characteristics. Can the available data be readily subdivided into groupings other than the five rate classes used in this study?

Response:

Yes, the data can be subdivided into groupings other than the five classes used in the study. Some alternative groupings can be accomplished more readily than others. The primary data challenges for grouping customers into classes involve customer usage data and design day data. Usage data is readily available by type of service, i.e. firm residential sales service, interruptible carriage service etc. Since some customers use multiple services, any customer grouping requires some customer by customer analysis. If further segregation is desired, such as separating customers who use over 200,000 mcf per year, additional customer by customer analysis would be required. Design day estimates are developed by areas or zones within Western for supply planning. Within each area, residential sales, firm commercial sales and firm industrial sales requirements are estimated in total for each group. Requirements for larger customers are developed on a customer by customer basis. Therefore, any customer grouping requires a customer by customer analysis to assign customers to customer groups.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, f
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

f. Mr. Petersen also states that the study was performed using fiscal year 1998 data and that results using the forecasted test period would follow a pattern similar to that of the historic cost-of-service analysis. Provide the results for the forecasted period and the appropriate workpapers in the same form as provided in the original filing (i.e., nineteen pages of model results and nine pages of supporting workpapers).

Response:

This item requests a study that has not been performed and cannot be completed by the due day for responding to these questions. The data necessary to perform the study is being assembled and the study will be provided upon completion.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, g
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

g. What are the results of the model for the historic test period normalized for weather using the proposed rates and the resulting revenue levels? What are the results of the model using the forecasted test year with the proposed rates and resulting revenue levels? Provide these results and the appropriate workpapers in the same form as provided in the original filing.

Response:

The attached study presents the class cost-of-service study for fiscal 1998 with revenues calculated by applying proposed rates to fiscal 1998 weather normalized usage. Please see the response to item 47f, for the class cost-of-service study using the forecasted test year with the proposed rates.

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE OF RETURN AT PROPOSED RATES
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No	Cost Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1	Total Operating Margins	58,832,845	33,664,978	13,477,236	1,498,327	4,497,037	5,695,268
2							
3	O & M Expense	23,121,835	12,633,644	5,605,253	485,648	1,450,887	2,946,403
4							
5	Deprec. & Amortization	6,486,839	3,836,843	1,605,100	131,167	331,123	582,606
6							
7	Property & Other Taxes	1,908,720	1,116,682	471,813	40,375	100,707	179,144
8							
9	Interest	4,754,687	2,733,603	1,162,396	104,084	262,977	491,628
10							
11	Pre-Tax Expenses	36,272,081	20,320,771	8,844,562	761,275	2,145,694	4,199,780
12							
13	Taxable Income	22,560,764	13,344,207	4,632,674	737,052	2,351,343	1,495,488
14							
15	Income Taxes	9,106,088	5,386,055	1,869,863	297,493	949,061	603,616
16							
17	Return	18,209,363	10,691,755	3,925,207	543,643	1,665,259	1,383,500
18							
19	Rate Base	124,468,251	71,560,291	30,429,217	2,724,703	6,884,208	12,869,831
20							
21	Rate Of Return	14.63%	14.94%	12.90%	19.95%	24.19%	10.75%

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE CLASS COMPARISONS

Line No	Description	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)
1	Average Annual Use Per Customer	86.2	371.2	7,414.7	53,027.2	1,000,011.3
2	Winter Season as a % of Annual Use	73.8%	70.2%	58.9%	46.7%	45.2%
3	Class Load Factor Average Day / Design Day	20.7%	21.1%	32.4%	36.2%	56.8%

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE CLASS COMPARISONS

Line No	Description	Firm Residential (a)	Firm Commercial (b)	Firm Industrial (c)	Interr. & Carriage (d)	Large Int. & Carr. (e)
1	Average Annual Use Per Customer	86.2	371.2	7,414.7	53,027.2	1,000,011.3
2	Winter Season as a % of Annual Use	73.8%	70.2%	58.9%	46.7%	45.2%
3	Class Load Factor Average Day / Design Day	20.7%	21.1%	32.4%	36.2%	56.8%

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE BASE - SEPTEMBER 30, 1998

Line No	Item	Total	Gas Cost	Storage	Distribution	Transmission	Production	Notes
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gas Plant	$203,141,249	$114,003	$5,518,920	$167,199,269	$29,373,900	$935,157	[1]
2	In Progress	17,179,026	10,307	467,270	14,140,056	2,484,087	77,306	[2]
3	Storage Cushion	1,694,833		1,694,833				[3]
4	Acquisition Adjustment	0	0	0	0	0	0	[1]
5	Material & Supplies	887,889		0	843,495	44,394		[7]
6	Gas Stored Underground	8,704,155		8,704,155				[4]
7	Prepayments	430,296	258	11,704	354,177	62,221	1,936	[1]
8	Prepaid Gas Purchases	166,569	166,569					[4]
9	Cash Requirements	2,890,229	44,510	58,094	2,678,954	108,095	576	[5]
10								
11		235,094,246	335,647	16,454,976	185,215,951	32,072,697	1,014,975	
12								
13	Deduct:							
14	Reserves:							
15	Deprec. & Amort.	94,938,460	6,772	3,764,514	74,025,104	16,307,871	834,198	[2]
16	Deferred Income Taxes	10,125,213	6,075	275,406	8,334,063	1,464,106	45,563	[1]
17	Customer Advances Const	5,562,323			5,284,207	278,116		[6]
18								
19		110,625,996	12,847	4,039,920	87,643,374	18,050,093	879,761	
20								
21								
22	Rate Base	124,468,251	322,801	12,415,055	97,572,577	14,022,604	135,214	

Notes
[1] Allocated By Gross Plant Percentage, See Sheet 1
[2] Identified Where Possible, Residual Allocated By Gross Plant Percentage, See Sheet 1
[3] Per Books
[4] Working Gas, test year average
[5] One Eighth O & M, Spread By O & M Percentage, Not Including Cost Of Gas, See Sheet 1
[6] 95% Distribution, 5% Transmission
[7] Fuel Stock To Storage Function; Balance, 95% Distribution, 5% Transmission

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
RATE BASE - CLASSIFICATION

ine No.	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Gas Cost	$322,801		$156,232	$166,569		[1]
2							
3	Storage	12,415,055		6,207,528	6,207,527		[2]
4							
5	Distribution	97,572,577	60,153,494	35,409,088	0	2,009,995	[3]
6							
7	Transmission	14,022,604		14,022,604			[4]
8							
9	Production	135,214		135,214			[4]
10							
11							
12	Total Rate Base	124,468,251	60,153,494	55,930,666	6,374,096	2,009,995	

Notes [1] Prepaid Gas Purchases Are All Commodity, Remainder All Demand
[2] 50% Demand, 50% Commodity
[3] Based On Distribution Plant Accounts, See Sheet 2
[4] 100 % Demand

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of RATE BASE to Classes of Service

Line No	Item	Alloc. Factor [2]	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large nt. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Gas Cost	A&P/Gas	$156,232	$92,333	$48,338	$8,499	$4,109	$2,953
2		Sales	166,569	94,212	50,087	10,794	10,144	1,332
3			322,801	186,545	98,425	19,293	14,253	4,285
4								
5	Storage	Design-B	6,207,528	3,817,009	1,989,513	312,859	32,900	55,247
6		Winter	6,207,527	2,139,114	1,081,351	219,746	700,209	2,067,107
7			12,415,055	5,956,123	3,070,864	532,605	733,109	2,122,354
8	Distribution [1]							
9	Mains	Cust-A	9,799,004	8,703,475	1,073,971	12,739	7,839	980
10		Design-A	33,472,211	13,539,509	7,059,289	1,111,277	4,003,276	7,758,858
11								
12	Services	Cust-D	28,025,513	19,914,930	8,110,583	0	0	0
13								
14	Meters	Cust-M	11,874,300	8,149,332	3,318,867	260,047	146,054	0
15								
16	Other	Cust-C	10,454,677	6,833,177	3,372,679	40,773	115,001	93,047
17		Design-A	1,936,877	783,467	408,487	64,304	231,651	448,968
18								
19	Direct - Other	Cust-E	2,009,995	0	0	25,326	1,097,859	886,810
20								
21	Total Distribution		97,572,577	57,923,890	23,343,876	1,514,467	5,601,681	9,188,663
22								
23	Transmission	A&P	14,022,604	7,422,164	3,878,652	652,051	530,054	1,539,682
24								
25	Production	A&P	135,214	71,569	37,400	6,287	5,111	14,847
26								
27	Total Rate Base		124,468,251	71,560,291	30,429,217	2,724,703	6,884,208	12,869,831

Note [1] Distribution Rate Base Divided Among Mains, Services Etc. By Applying The Percent Of Total Classification In Distribution Accounts From Sheet 2 To The Classified Amounts From Page 4

[2] Allocation Factors Derived On Pages 16 And 17

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
GAS COST - CLASSIFICATION

Line No	Item	Total	Customer	Demand	Commodity	Direct	Notes
		(a)	(b)	(c)	(d)	(e)	(f)
1	Purchased Exp.	24,333			24,333		[1]
2							
3	Admin. & General	332,431		332,431			[2]
4							
5	Depre. & Amortization	378	0	183	195	0	[3] [2]
6							
7	Property & Other Taxes	1,145	0	554	591	0	[3] [5]
8							
9	Return	32,183	0	15,577	16,606	0	[3] [6]
10							
11	Income Taxes	13,472	0	6,520	6,952	0	[3] [4]
12							
13							
14	Revenue Requirement	403,942	0	355,265	48,677	0	

Notes
[1] Total From Sheet 4
[2] Allocated To Functions On Sheet 1
[3] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[4] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1
[5] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[6] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of GAS COSTS to Classes of Service

Line No	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Purchased Exp.	Vol-A	24,333	6,482	3,446	835	3,353	10,217
2								
3	Admin. & General	A&P/Gas	332,431	196,467	102,854	18,084	8,743	6,283
4								
5								
6	Depre. & Amortization	Rb-Dem	183	84	44	7	16	32
7		Rb-Com	195	68	35	7	22	63
8								
9	Property & Other Taxes	Rb-Dem	554	255	133	21	48	97
10		Rb-Com	591	207	105	21	66	192
11								
12	Return	Rb-Dem	15,577	7,165	3,738	600	1,339	2,735
13		Rb-Com	16,606	5,818	2,948	601	1,851	5,388
14								
15	Income Taxes	Rb-Dem	6,520	2,999	1,565	251	560	1,145
16		Rb-Com	6,952	2,436	1,234	251	775	2,256
17								
18								
19	Revenue Requirement		403,942	221,981	116,102	20,678	16,773	28,408

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
STORAGE - CLASSIFICATION

Line No.	Item	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)	Notes (f)
1	Accts. 818 & 819	$72,474			$72,474		[1] [3]
2							
3	All Other Accounts	242,575		121,288	121,287		[2] [3]
4							
5	Lp Expenses	2		2			[3]
6							
7	Admin. & General	149,008		74,504	74,504		[2] [5]
8							
9	Depre. & Amortization	217,604	0	108,802	108,802	0	[4] [5]
10							
11	Property & Other Taxes	51,917	0	25,959	25,958	0	[4] [6]
12							
13	Return	1,237,781	0	618,891	618,890	0	[4] [7]
14							
15	Income Taxes	516,590	0	258,295	258,295	0	[4] [8]
16							
17							
18	Revenue Requirement	2,487,951	0	1,207,741	1,280,210	0	

Notes
[1] Compressor Station Expense Fuel Accounts, 100 % Commodity
[2] 50 % Demand, 50% Commodity
[3] Total From Sheet 4
[4] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[5] Allocated To Functions On Sheet 1
[6] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[7] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[8] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of STORAGE COSTS to Classes of Service

Line No	Item	Alloc. Factor	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Accts. 818 & 819	Winter	$72,474	$24,975	$12,625	$2,566	$8,175	$24,133
2								
3	All Other Accounts	Design-B	121,288	74,580	38,873	6,113	643	1,079
4		Winter	121,287	41,796	21,128	4,294	13,681	40,388
5								
6	Lp Expenses	Design-B	2	1	1	0	0	0
7								
8	Admin. & General	Design-B	74,504	45,813	23,879	3,755	395	662
9		Winter	74,504	25,674	12,979	2,637	8,404	24,810
10								
11	Depr. & Amortizatio	Rb-Dem	108,802	50,045	26,109	4,193	9,351	19,104
12		Rb-Com	108,802	38,122	19,313	3,935	12,125	35,307
13								
14	Property & Other Ta	Rb-Dem	25,959	11,940	6,229	1,000	2,231	4,559
15		Rb-Com	25,958	9,095	4,608	939	2,893	8,424
16								
17	Return	Rb-Dem	618,891	284,667	148,515	23,849	53,192	108,668
18		Rb-Com	618,890	216,844	109,856	22,384	68,971	200,835
19								
20	Income Taxes	Rb-Dem	258,295	118,806	61,983	9,953	22,200	45,353
21		Rb-Com	258,295	90,500	45,849	9,342	28,785	83,819
22								
23								
24	Revenue Requirement		2,487,951	1,032,858	531,947	94,960	231,046	597,141

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
DISTRIBUTION - CLASSIFICATION

Line No	Item	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)	Notes (f)
1	Accts. 876 & 890	$290,520				$290,520	[1] [5]
2	98% Of Accts. 901 - 910	5,789,626	5,789,626				[2] [5]
3	64% of Accts. 911 - 916	52,154			52,154		[3] [5]
4	Admin. & General	6,882,115	2,294,038	2,294,038	2,294,039		[4] [8]
5	98% Of Accts. 878,879, 880,892,893,894	2,292,526	2,292,526				[5]
6	Other Accts. 870 Through 894	6,126,196	1,386,971	4,739,225			[6] [5]
7	Depre. & Amortization	5,624,201	3,467,319	2,041,023	0	115,859	[7] [8]
8	Property & Other Taxes	1,571,067	968,563	570,140	0	32,364	[7] [9]
9	Return	9,727,986	5,997,303	3,530,286	0	200,397	[7] [10]
10	Income Taxes	4,061,732	2,504,057	1,474,003	0	83,672	[7] [11]
11	Revenue Requirement	42,418,123	24,700,403	14,648,715	2,346,193	722,812	

Notes
[1] O/M - Meas. And Reg. Station Accounts - Industrial, Direct Assigned
[2] Customer Accounts Expenses, 100 % Customer
[3] Sales Expenses Accounts, 100 % Commodity
[4] 1/3 To Each: Customer, Demand, Commodity
[5] Total From Sheet 4
[6] Used Plant Allocator, Sheet 4
[7] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[8] Allocated To Functions On Sheet 1
[9] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[10] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[11] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of DISTRIBUTION COSTS to Classes of Service

Line No.	Item	Alloc. Factor (a)	Total (b)	Firm Residential (c)	Firm Commercial (d)	Firm Industrial (e)	Interr. & Carriage (f)	Large Int. & Carr. (g)
1	Accts. 876 & 890 Direct	Cust-E	$290,520	$0	$0	$3,661	$158,682	$128,177
2								
3	98% Of Accts. 901 - 910	Cust-B	5,789,626	3,813,627	1,882,208	56,738	31,843	5,210
4								
5	64% Of Accts. 911 - 916	Vol-A	52,154	13,894	7,385	1,789	7,187	21,899
6								
7	Admin. & General	Cust-A	2,294,038	2,037,565	251,427	2,982	1,835	229
8		Vol-A	2,294,039	611,132	324,836	78,686	316,119	963,266
9		Design-A	2,294,038	927,938	483,813	76,162	274,367	531,758
10								
11	98% Of Accts 878,879,							
12	880,892,893,894	Cust-B	2,292,526	1,510,087	745,300	22,467	12,609	2,063
13								
14	Other Accts 870 Through	Cust-B	1,386,971	913,598	450,904	13,592	7,628	1,249
15	894	Design-A	4,739,225	1,917,017	999,503	157,342	566,811	1,098,552
16								
17	Depre. & Amortization	Rb-Cus	3,467,319	2,513,209	915,117	18,074	15,499	5,420
18		Rb-Dem	2,041,023	938,796	489,784	78,650	175,421	358,372
19		Rb-Dir	115,859	0	0	1,460	63,282	51,117
20								
21	Property & Other Taxes	Rb-Cus	968,563	702,041	255,629	5,049	4,330	1,514
22		Rb-Dem	570,140	262,243	136,816	21,970	49,002	100,109
23		Rb-Dir	32,364	0	0	408	17,677	14,279
24								
25	Return	Rb-Cus	5,997,303	4,347,011	1,582,847	31,262	26,809	9,374
26		Rb-Dem	3,530,286	1,623,802	847,163	136,039	303,419	619,863
27		Rb-Dir	200,397	0	0	2,525	109,457	88,415
28								
29	Income Taxes	Rb-Cus	2,504,057	1,815,010	660,887	13,053	11,193	3,914
30		Rb-Dem	1,474,003	677,987	353,716	56,800	126,687	258,813
31		Rb-Dir	83,672	0	0	1,054	45,702	36,916
32								
33								
34	Revenue Requirement		42,418,123	24,624,957	10,387,335	779,763	2,325,559	4,300,509

Line No.	Item	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)	Notes (f)
1	Accts. 850 - 867	$392,071		$392,071			[1]
2							
3	2% Of Accts. 878,879,						
4	880,892,893,894	46,786	46,786				[1]
5							
6	Admin. & General	277,322		277,322			[4]
7							
8	36% Of Accts. 911 - 916	29,336			29,336		[1]
9							
10	2% Of Accts. 901 - 910	118,156	118,156				[1]
11							
12	Depre. & Amortization	641,822	0	641,822	0	0	[2] [3]
13							
14	Property & Other Taxes	276,001	0	276,001	0	0	[2] [4]
15							
16	Return	1,398,054	0	1,398,054	0	0	[2] [5]
17							
18	Income Taxes	583,948	0	583,948	0	0	[2] [6]
19							
20							
21	Revenue Requirement	3,763,496	164,942	3,569,218	29,336	0	

Notes
[1] Total From Sheet 4
[2] Classified Based On Rate Base Classification Percentage Table Sheet 2
[3] Allocated To Functions On Sheet 1
[4] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[5] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[6] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of TRANSMISSION COSTS to Classes of Service

Line No	Item	Alloc. Factor (a)	Total (b)	Firm Residential (c)	Firm Commercial (d)	Firm Industrial (e)	Interr. & Carriage (f)	Large Int. & Carr. (g)
1	Accts 850-865	A&P	$392,071	$207,523	$108,447	$18,231	$14,820	$43,050
2								
3	2% Of Accts 878,879,							
4	880,892,893,894	Cust-B	46,786	30,818	15,210	459	257	42
5								
6	Admin. & General	A&P	277,322	146,787	76,707	12,895	10,483	30,450
7								
8	36% Of Accts. 911 - 916	Vol-A	29,336	7,815	4,154	1,006	4,043	12,318
9								
10	2% Of Accts. 901 - 910	Cust-B	118,156	77,829	38,412	1,158	650	107
11								
12	Depre. & Amortization	Rb-Dem	641,822	295,215	154,018	24,732	55,163	112,694
13								
14	Property & Other Taxes	Rb-Dem	276,001	126,950	66,232	10,636	23,722	48,461
15								
16	Return	Rb-Dem	1,398,054	643,053	335,491	53,874	120,159	245,477
17								
18	Income Taxes	Rb-Dem	583,948	268,595	140,130	22,502	50,189	102,532
19								
20								
21	Revenue Requirement		3,763,496	1,804,585	938,801	145,493	279,486	595,130

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
PRODUCTION - CLASSIFICATION

Line No.	Item	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)	Notes (f)
1	Accts 750-798	$2,854		$2,854			[1]
2							
3	Admin. & General	1,350		$1,350			[3]
4							
5	Depre. & Amortization	2,834	0	2,834	0	0	[2] [3]
6							
7	Property & Other Taxes	8,590	0	8,590	0	0	[2] [4]
8							
9	Return	13,481	0	13,481	0	0	[2] [5]
10							
11	Income Taxes	5,699	0	5,699	0	0	[2] [6]
12							
13							
14	Revenue Requirement	34,808	0	34,808	0	0	

NOTES
[1] Total From Sheet 4
[2] Classified Based On Rate Base Classification Percentage Table, Sheet 2
[3] Allocated To Functions On Sheet 1
[4] Total From Sheet 4; Allocated To Functions By Gross Plant Pct., Sheet 1
[5] Rate Of Return From Sheet 4; Applied To Functional Rate Base, Page 3
[6] Total From Sheet 4; Allocated To Functions By Rate Base Pct., Sheet 1

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Allocation of PRODUCTION COSTS to Classes of Service

Line No	Item	Alloc. Factor (a)	Total (b)	Firm Residential (c)	Firm Commercial (d)	Firm Industrial (e)	Interr. & Carriage (f)	Large Int. & Carr. (g)
1	Accts 750-798	A&P	$2,854	$1,511	$789	$133	$108	$313
2								
3	Admin. & General	A&P	1,350	715	373	63	51	148
4								
5	Depre. & Amortization	Rb-Dem	2,834	1,304	680	109	244	497
6								
7	Property & Other Taxes	Rb-Dem	8,590	3,951	2,061	331	738	1,509
8								
9	Return	Rb-Dem	13,481	6,201	3,235	519	1,159	2,367
10								
11	Income Taxes	Rb-Dem	5,699	2,621	1,368	220	490	1,000
12								
13								
14	Revenue Requirement		34,808	16,303	8,506	1,375	2,790	5,834

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Derivation of COST ALLOCATORS at Normalized Volumes

Line No	Item	Total (a)	Firm Residential (b)	Firm Commercial (c)	Firm Industrial (d)	Interr. & Carriage (e)	Large Int. & Carr. (f)	Cost Allocator (g)
1	Annual Volume-Mcf							
2	Total	50,014,309	13,324,639	7,083,095	1,712,796	6,893,542	21,000,237	
3		1.0000	0.2664	0.1416	0.0343	0.1378	0.4199	Vol-A
4	Regular Sales	23,558,414	13,324,639	7,083,095	1,526,449	1,435,663	188,568	
5		1.0000	0.5656	0.3007	0.0648	0.0609	0.0080	Sales
6	LVS Sales	629,986	0	0	2,931	328,819	298,236	
7		1.0000	0.0000	0.0000	0.0047	0.5219	0.4734	LVS
8	Total Sales	##########	##########	7,083,095	1,529,380	1,764,482	486,804	
9		1.0000	0.5509	0.2928	0.0632	0.0730	0.0201	TotSales
10	Sales & Stand-by [1]	25,732,793	13,324,639	7,083,095	1,712,796	2,336,335	1,275,928	
11		1.0000	0.5178	0.2752	0.0666	0.0908	0.0496	W/Gas
12								
13	Winter Period-Mcf [2]							
14	Total	28,532,291	9,831,002	4,971,215	1,009,350	3,220,127	9,500,597	
15		1.0000	0.3446	0.1742	0.0354	0.1128	0.3330	Winter
16								
17	Design Day-Mcf [3]							
18	G-1	287,219	176,618	92,063	14,477	1,519	2,542	
19	G-2/T-3/T-4	149,370				50,681	98,689	
20	Total	436,589	176,618	92,063	14,477	52,200	101,231	
21	Not Curtailed	1.0000	0.4045	0.2109	0.0332	0.1196	0.2318	Design-A
22	Curtailed	1.0000	0.6149	0.3205	0.0504	0.0053	0.0089	Design-B
23								
24	No. Of Customers							
25	12 Month Average	174,127	154,661	19,084	231	130	21	
26	Percent	1.0000	0.8882	0.1096	0.0013	0.0008	0.0001	Cust-A
27	Wt., R/C/I=1:4:10 [4]	1.0000	0.6587	0.3251	0.0098	0.0055	0.0009	Cust-B
28	Wt., 1:4:4:20:100	1.0000	0.6536	0.3226	0.0039	0.0110	0.0089	Cust-C
29								
30	Excl. Industrial	173,745	154,661	19,084				
31	Wt., 1:3.3	1.0000	0.7106	0.2894				Cust-D
32								
33	Large Customers [5]	154		0	3	130	21	
34	Weighted, 1:1:5	1.0000		0.0000	0.0126	0.5462	0.4412	Cust-E
35								
36	Meter Investment		154,661	19,084	231	130		
37	Wt., 1:3.3:21.4	1.0000	0.6863	0.2795	0.0219	0.0123		Cust-M
38								
39	Average & Peak [6]	1.0000	0.5293	0.2766	0.0465	0.0378	0.1098	A&P
40	Avg & Peak for Gas [7	1.0000	0.5910	0.3094	0.0544	0.0263	0.0189	A&P/Gas
41	Load Factor [8]	0.2455						

Notes
[1] Total sales volumes plus transportation volumes with sales stand-by rights
[2] November Through March
[3] Daily Contract Demands For Rate 1 Industrial, G-2 And Large G-2 Customers And Estimated Design Day Use For Other Customers
[4] Number of Customers are weighted: Residential/Commercial/Industrial = 1/4/10
[5] G-1 Customers With 240 Mcf Daily Contract Demand Plus G-2 & Large G-2 Customers
[6] Vol-A Times Load Factor Plus Design-B Times One Minus Load Factor
[7] W/Gas Times Load Factor Plus Design-B Times One Minus Load Factor
[8] Normalized Annual Sales & Standby Volumes Divided By Annualized Design Day System Requirements

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Derivation of COST ALLOCATORS from Rate Base

Line No	Cost Component	Cost Allocator	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Customer		###########	###########	###########	$313,559	$268,894	$94,027
2		Rb-Cus	1.00000	0.72483	0.26393	0.00521	0.00447	0.00156
3								
4	Demand		55,930,666	25,726,052	13,421,680	2,155,277	4,807,102	9,820,555
5		Rb-Dem	1.00000	0.45996	0.23997	0.03853	0.08595	0.17558
6								
7	Commodity		6,374,096	2,233,326	1,131,438	230,540	710,353	2,068,439
8		Rb-Com	1.00000	0.35038	0.17751	0.03617	0.11144	0.32451
9								
10	Direct		2,009,995	0	0	25,326	1,097,859	886,810
11		Rb-Dir	1.00000	0.00000	0.00000	0.01260	0.54620	0.44120
12								
13								
14	TOTAL		###########	71,560,291	30,429,217	2,724,703	6,884,208	12,869,831
15								
16		Rb-Total	1.00000	0.57493	0.24447	0.02189	0.05531	0.10340

WESTERN KENTUCKY GAS COMPANY
BILL FREQUENCY ANALYSIS
TWELVE MONTHS ENDED SEPTEMBER 30, 1998

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		RESIDENTIAL				FIRM COMMERCIAL				FIRM INDUSTRIAL			
		Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
1	FIRM BILLS	#########		$9.00	$16,703,352	229,012		$24.00	$5,496,288	2,770		$24.00	$66,480
2	Transport. Bills	0				0		50.00	-	108		50.00	5,400
	ParkingFees												178
3	Sales: 1-300		##########	1.2000	15,989,567		5,819,317	1.2000	6,983,180		443,296	1.2000	531,955
4	Sales: 301-15000		0	0.6946	0		1,263,778	0.6946	877,820		1,083,153	0.6946	752,358
5	Trans: 1-300						0	1.2000	0		17,016	1.2000	20,419
6	Trans: 301-15000						0	0.6946	0		166,400	0.6946	115,581
7	LVS: 1-300							1.2000			372	1.2000	446
8	LVS: 301-15000							0.6946			2,559	0.6946	1,777
9													
10	Total		##########		$32,692,919		7,083,095		###########		1,712,796		$1,494,594
11													
12													
13						INTERRUPTIBLE CUSTOMERS				LARGE INTERRUPTIBLE CUSTOMERS			
14						Number Of Bills	Mcf	Rate	Total Revenue	Number Of Bills	Mcf	Rate	Total Revenue
15	Bills					1,555		$250.00	$388,750	251		$250.00	$62,750
16	Transport. Bills					1,121		$50.00	$56,050	239		$50.00	$11,950
17	Parking Fees												52,474
18	Firm Sales: 1-300						36,188	1.2000	43,426		3,000	1.2	3,600
19	Firm Sales: 301-15000						140,672	0.6946	97,711		12,028	0.6946	8,355
20	Firm Sales: Over 15000						2,108	0.4299	906		0	0.4299	0
21	Firm Trans: 1-300						8,939	1.2000	10,727		4,500	1.2	5,400
22	Firm Trans: 301-15000						95,700	0.6946	66,473		238,829	0.6946	165,891
23	Firm Trans: Over 15000						0	0.4299	0		78,311	0.4299	33,666
24	Firm LVS: 1-300						2,700	1.2000	3,240		3,900	1.2	4,680
25	Firm LVS: 301-15000						68,715	0.6946	47,729		13,815	0.6946	9,596
26	Firm LVS: Over 15000						6,711	0.4299	2,885		0	0.4299	0
27	T-4: 1-300						136,605	1.2000	163,926		32,100	1.2	38,520
28	T-4: 301-15000						1,760,007	0.6946	1,222,501		919,996	0.6946	639,029
29	T-4: Over 15000						7,076	0.4299	3,042		524,473	0.4299	225,471
30	Interrupt Sales: 1-15000						982,994	0.5300	520,987		116,691	0.53	61,846
31	Interrupt Sales: Over 15000						129,546	0.3301	42,763		22,939	0.3301	7,572
32	Interrupt Transport: 1-15000						459,426	0.5300	243,496		327,138	0.53	173,383
33	Interrupt Transport: Over 15000						7,788	0.3301	2,571		140,346	0.3301	46,328
34	Interrupt LVS: 1-15000						145,693	0.5300	77,217		161,050	0.53	85,357
35	Interrupt LVS: Over 15000						105,000	0.3301	34,661		119,471	0.3301	39,437
36	Carriage:1-15000						2,324,362	0.5300	1,231,912		1,852,647	0.53	981,903
37	Carriage:Over 15000						26,074	0.3301	8,607		3,467,803	0.3301	1,144,722
38	T-4 Overrun 0-300						11,639	1.3200	15,363		0	1.32	0
39	T-4 Overrun 301-15000						23,390	0.7641	17,872		2,020	0.7641	1,543
40	T-3 Overrun 0-15000						109,126	0.5830	63,620		31,890	0.5830	18,592
41	Special Contracts						303,083	various	71,976		12,927,290	various	1,855,349
42													
43	CLASS TOTAL						6,893,542		$4,438,411		21,000,237		$5,677,414
44													
45	GRAND TOTAL										50,014,309		$57,660,626

WESTERN KENTUCKY GAS COMPANY
CLASS COST OF SERVICE STUDY
Monthly Customer Cost

ine No.	Customer Cost	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large nt. & Carr
		(a)	(b)	(c)	(d)	(e)	(f)
1	O &M Expense	###########	$8,383,524	$3,383,461	$101,057	$213,504	$137,077
2							
3	Depreciation & Amortization	3,583,178	2,513,209	915,117	19,534	78,781	56,537
4							
5	Property & Other Taxes	1,000,927	702,041	255,629	5,457	22,007	15,793
6							
7	Income Taxes	2,587,729	1,815,010	660,887	14,107	56,895	40,830
8							
9	Return	6,197,700	4,347,011	1,582,847	33,787	136,266	97,789
10							
11							
12	Total	25,588,157	17,760,795	6,797,941	173,942	507,453	348,026
13							
14							
15	Number Of Customers	174,127	154,661	19,084	231	130	21
16							
17	Customer Cost Per Customer						
18	Per Month	$12.25	$9.57	$29.68	$62.75	$325.29	$1,381.06

WESTERN KENTUCKY GAS COMPANY
FUNCTIONAL ALLOCATIONS

Line No.		Total	Gas Cost	Storage	Distribution	Transmission	Production	Sub Total	Intangible	General Plant	Div 02 Gross Plant
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	RATE BASE ITEMS										
1	Gas Plant [1]	203,141,249	100,000	4,884,111	147,989,309	25,999,146	830,133	179,802,699	128,182	16,646,897	6,563,471
2	Gross Plant Pct. (Grsplt%)		0.06%	2.72%	82.31%	14.46%	0.45%	100.00%			
3	Other Alloc By Grsplt%		14,003	634,809	19,209,960	3,374,754	105,024	23,338,550			
4	With Alloc By Grsplt%	203,141,249	114,003	5,518,920	167,199,269	29,373,900	935,157	203,141,249			
5	In Progress										
		2,196,907	1,318	59,756	1,808,274	317,673	9,886	2,196,907			14,982,119
6	With Alloc By Grsplt%	17,179,026	10,307	467,270	14,140,056	2,484,087	77,306	17,179,026			
7	Reserve For Depreciation	94,938,460	0	3,457,534	64,735,565	14,675,910	783,411	83,652,420	119,853	8,242,541	2,923,646
8	With Alloc By Grsplt%	94,938,460	6,772	3,764,514	74,025,104	16,307,871	834,198	94,938,460			
9											
10	Net Rate Base	124,468,251	322,801	12,415,055	97,572,577	14,022,604	135,214				
11	Rate Base Percentage	100.00%	0.26%	9.97%	78.39%	11.27%	0.11%				
11	EXPENSES										
12	Deprec. & Amort. Expense	6,486,839	0	200,474	5,105,830	550,756	0	5,857,060	0	629,779	
13	With Alloc By Grsplt%	6,486,839	378	217,604	5,624,201	641,822	2,834	6,486,839		0	
14	Admin.& General Expense [2]	7,642,226	332,431	149,008	6,882,115	277,322	1,350				
15	Other Non-Gas O&M	15,479,609	24,333	315,051	14,551,022	586,349	2,854				
16	Operation & Maintenance	23,121,835	356,764	464,059	21,433,137	863,671	4,204				
17	O&M Percentage	100.00%	1.54%	2.01%	92.69%	3.74%	0.02%				

[1] Excluding Acquisition Adjustment, moved $3,189,471 of additions to 6 and 8 inch mains from distribution to transmission

[2] Administrative And General Expenses Allocated To Functions In Proportion To Other Non-Gas O&M Except That Gas Supply Department Expenses Are Allocated Directly To Gas Cost

WESTERN KENTUCKY GAS COMPANY
SUPPORT FOR CLASSIFICATIONS

ine No.		Category	Total (a)	Customer (b)	Demand (c)	Commodity (d)	Direct (e)
	ACCT.	DISTRIBUTION PLANT ACCOUNT					
1	374.10	Land- T.B.	58,433	13,229	45,204		
2	374.20	Land- Other	44,872	10,159	34,713		
3	374.30	Rights-Of-Way	2,784	630	2,154		
4	375.10	Structures & Impr.	106,376	24,084	82,292		
5	375.03	Improvements	7,518	1,702	5,816		
6	375.20	Land Rights	46,591	10,548	36,043		
7	376.00	Mains (adj. Per sheet 1)	65,628,322	14,858,252	50,770,070		
8	378.10	Meas. & Reg General	1,881,560	425,985	1,455,575		
9	379.30	Meas & Reg Other	1,650,884	373,760	1,277,124		
10	380.00	Services	42,501,668	42,501,668			
11	381.00	Meters	18,009,721	18,009,721			
12	381.20	Gauges	109,765				109,765
13	382.00	Meter Installations	10,938,730	10,938,730			
14	383.00	House Regulators Service	3,428,992	3,428,992			
15	383.20	House Regulators Relief	481,544	481,544			
16	384.00	House Reg. Installations	154,276	154,276			
17	385.00	Meas & Reg Indust.	2,937,272				2,937,272
18							0
19							
20	TOTAL DISTRIBUTION PLANT		147,989,308	91,233,280	53,708,991	0	3,047,037
21		Percent Of Total	100.00%	61.65%	36.29%	0.00%	2.06%
22							
23	PERCENT OF TOTAL CLASSIFICATION IN ACCOUNTS:						
24							
25	376.00	Mains		16.29%	94.53%		
26	380.00	Services		46.59%	0.00%		
27	381.00	Meters		19.74%	0.00%		
28		All Others		17.38%	5.47%		100.00%
29							
30		Total		100.00%	100.00%		100.00%
31							
32							
33	RATE BASE - CLASSIFICATION PERCENTAGE						
34							
35		Gas Cost	100.00%	0.00%	48.40%	51.60%	0.00%
36		Storage	100.00%	0.00%	50.00%	50.00%	0.00%
37		Distribution	100.00%	61.65%	36.29%	0.00%	2.06%
38		Transmission	100.00%	0.00%	100.00%	0.00%	0.00%
39		Production	100.00%	0.00%	100.00%	0.00%	0.00%
40							
41		Total Rate Base	100.00%	48.33%	44.94%	5.12%	1.61%

WESTERN KENTUCKY GAS COMPANY
12 MONTH AVERAGES

Sum of Ending Balance		Month						
Account		October-97	November-97	December-97	January-98	February-98	March-98	April-98
1540	Cur Asset-Plnt Matls & Op	1,030,998.16	1,004,680.71	912,053.72	856,270.93	961,167.10	922,488.23	806,611.13
1550	Current Assets-Merchandis	22,723.44	21,230.17	21,813.88	20,757.12	20,643.51	19,234.44	17,074.27
1630	Cur Asset-Stores Expense	446,663.48	453,178.21	422,761.79	421,714.19	410,284.83	409,081.80	388,664.37
1640	Cur Asset-U/G Stored Gas	11,776,167.85	13,232,086.28	12,937,192.86	10,002,571.05	7,921,546.78	5,671,434.03	3,568,139.93
1660	Cur Asset-Prepayments	1,589,760.84	625,862.16	607,162.36	594,752.65	556,270.82	538,953.24	475,813.08
within 166	prepaid gas all.	1,172,398.13	82,643.27	82,643.27	82,643.27	82,643.27	82,643.27	82,643.27

		May-98	June-98	July-98	August-98	September-98	Grand Total	Average
1540	Cur Asset-Plnt Matls & Op	845,724.40	875,035.97	836,239.81	818,908.08	784,493.39	10,654,671.63	887,889.30
1550	Current Assets-Merchandis	16,266.93	15,275.01	15,160.36	13,458.85	13,072.94	216,710.92	18,059.24
1630	Cur Asset-Stores Expense	400,293.09	419,922.52	432,573.00	434,889.62	451,226.71	5,091,253.61	424,271.13
1640	Cur Asset-U/G Stored Gas	5,691,691.84	5,691,236.36	7,199,700.77	9,414,382.47	11,343,705.04	104,449,855.26	8,704,154.61
1660	Cur Asset-Prepayments	440,996.96	427,618.52	566,568.99	522,256.14	216,366.92	7,162,382.68	596,865.22
within 166	prepaid gas all.	82,643.27	82,643.27	82,643.27	82,643.27	0	1,998,830.83	166,569.24

WESTERN KENTUCKY GAS COMPANY
MISCELLANEOUS INPUTS

ine no.	O&M To Functions - Detail	Per Books	Adjustments	Total
		(a)	(b)	(c)
1	Gas Cost: 807	24,333		24,333
2	Lp: 717 Through 742	2		2
3	Production: 750 Through 798	2,854		2,854
4	Storage: 818 & 819	72,474		72,474
5	Storage: Other Accounts	242,575		242,575
6	Transmission	392,071		392,071
7	Distribution: 878,879,880,892,893,894	2,339,312		2,339,312
8	Distribution: 876 & 890	290,520		290,520
9	Distribution: Other Accounts	6,126,196		6,126,196
10	Customer Accts & Services: 901 - 910	4,975,189	932,593	5,907,782
11	Sales Expenses: 911 - 916	81,490		81,490
12	A&G Expenses	7,642,226		7,642,226
13				
14	Total Non-Gas O&M And A&G	22,189,242		23,121,835
15				
16				
17				
18	Plant Allocator (From Sheet 7)			
19	Demand	0.7736		
20	Customer	0.2264		
21				
22	Interest Expense	4,754,687		
23				
24	Combined Income Tax Rate	0.403625		
25	Income Taxes	5,181,441		
26				
27	Property & Other Taxes	1,908,720		
28				
29				
30	Proposed after tax return on Rate Base			
31	Equity return	6.15%		
32	Debt return	3.82%		
33	Proposed Rate Of Return On Rate Base	9.97%		
34				
35				
36	Pretax return on Rate Base			
37	Equity return	10.31%		
38	Debt return	3.82%		
39	Total return	14.13%		
40				
41	General Office Allocation Percent	16.66%		

WESTERN KENTUCKY GAS COMPANY
TOTALS FROM PAGES 6 THROUGH 15 OF STUDY

Line No	Classification	(a) Total	(b) Customer	(c) Monthly Demand	(d) Commodity	(e) Direct	(f)
1	O & M	23,121,835	11,928,103	8,235,085	2,668,127	290,520	
2	Depreciation & Amort	6,486,839	3,467,319	2,794,664	108,997	115,859	
3	Property & Other Taxes	1,908,720	968,563	881,244	26,549	32,364	
4	Return	12,409,485	5,997,303	5,576,289	635,496	200,397	
5	Income Taxes	5,181,441	2,504,057	2,328,465	265,247	83,672	
6	Revenue Requirement	49,108,320	24,865,345	19,815,747	3,704,416	722,812	
7							
8							
9							
10							
11							
12			Firm	Firm	Firm	Interr. &	Large
13	Allocation To Classes	Total	Residential	Commercial	Industrial	Carriage	nt. & Carr.
14							
15	O & M	23,121,835	12,633,644	5,605,253	485,648	1,450,887	2,946,403
16	Depreciation & Amort	6,486,839	3,836,843	1,605,100	131,167	331,123	582,606
17	Property & Other Taxes	1,908,720	1,116,682	471,813	40,375	100,707	179,144
18	Return	12,409,485	7,134,561	3,033,793	271,653	686,356	1,283,122
19	Income Taxes	5,181,441	2,978,954	1,266,732	113,427	286,581	535,748
20	Revenue Requirement	49,108,320	27,700,684	11,982,690	1,042,270	2,855,654	5,527,022

WESTERN KENTUCKY GAS COMPANY
REVENUE AT PRESENT AND PROPOSED RATES

ine No.	Cost Item	Total	Firm Residential	Firm Commercial	Firm Industrial	Interr. & Carriage	Large Int. & Carr.
		(a)	(b)	(c)	(d)	(e)	(f)
1							
2	Revenue:						
3							
4	Gas Operating Margins	$57,660,626	$32,692,919	$13,357,288	$1,494,594	$4,438,411	$5,677,414
5							
6	EFM Revenue	77,805	0	0	2,310	57,750	17,745
7							
8	Other Revenue	1,094,414	972,059	119,948	1,423	876	109
9							
10	Total Operating Margins	58,832,845	33,664,978	13,477,236	1,498,327	4,497,037	5,695,268

WESTERN KENTUCKY GAS COMPANY
DISTRIBUTION MAINS STUDY
Test Year Ended September 30, 1998

ine No	(1) Size	(2) X	(3) W Feet	(4) W*X	(5) W*Y $	(6) Y $ Per Foo	(7) X-avgX	(8) W(X-avgX)	(9) Y-avgY	(10) W(Y-avgY)	(11) (8)*(9)	(12) (8)*(7) (1)
1	<2"	1	784,916	784,916	1,734,239	2.2095	(4.67)	(3,662,941)	(1.73)	(1,356,127)	6,328,592	17,093,726
2	2"	2	##########	21,057,624	32,944,091	3.1289	(3.67)	###########	(0.81)	(8,509,876)	31,202,879	141,554,028
3	3"	3	431,511	1,294,533	850,463	1.9709	(2.67)	(1,150,696)	(1.97)	(848,479)	2,262,611	3,068,523
4	4"	4	3,373,749	13,494,996	21,648,330	6.4167	(1.67)	(5,622,915)	2.48	8,365,228	###########	9,371,525
5	5"	5	6,015	30,075	6,396	1.0633	(0.67)	(4,010)	(2.87)	(17,286)	11,524	2,673
6	6"	6	661,535	3,969,210	4,542,356	6.8664	0.33	220,512	2.93	1,937,765	645,922	73,504
7	8"	8	96,603	772,824	778,745	8.0613	2.33	225,407	4.12	398,400	929,601	525,950
8	10"	10	12,265	122,650	78,531	6.4029	4.33	53,148	2.47	30,241	131,046	230,309
9	12"	12	6	72	157	26.1667	6.33	38	22.23	133	845	241
10												
11	Total	51.00	##########	41,526,900	62,583,308		0.00	###########	26.85	0	27,570,972	171,920,479
12												
13	Average	5.67				3.9372						
14												
15												

Line	(13) Size	(14) Ycalc A+B*X	(15) Y-Ycalc	(16) W*(15)^2	(17) W*(9)^2
19					
20	<2"	2.06	0.15	18,163	2,343,028
21	2"	3.22	(0.09)	93,405	6,878,078
22	3"	4.39	(2.42)	2,522,995	1,668,363
23	4"	5.55	0.86	2,506,706	20,741,628
24	5"	6.72	(5.66)	192,502	49,678
25	6"	7.89	(1.02)	688,155	5,676,091
26	8"	10.22	(2.16)	449,295	1,643,042
27	10"	12.55	(6.15)	463,385	74,565
28	12"	14.88	11.29	764	2,965
29					
30	Total	67.48	(5.19)	6,935,370	39,077,438
31					
32	TOT. >2"		4,581,684	###########	6.0906
33	@ 2" PRICE		4,581,684	###########	3.1289
34	Difference		4,581,684	###########	2.9616
35					
36	0-Intercept		##########	###########	0.8915

(18)
Calculated From
<u>Column Totals</u>

Y = A + B*X
B = [(3)*(11)-(9)*(8)]/[(3)*(12)-(8)^2]
A = (5)/(3)-B*[(4)/(3)]
R^2 = 1-[(16)/(17)*[9-1]/[9-2]

B = 1.1658

A = 0.8915

R^2 = 0.7972

Minimum System		
Demand	###########	21.68%
Customer	###########	78.32%
Regression Minimum		
Demand	###########	77.36%
Customer	###########	22.64%

WESTERN KENTUCKY GAS COMPANY
METER ANALYSIS
September 1998

Meters	Type	Number	Investment	Invest/Meter
(a)	(b)	(c)	(d)	(e)
Group A	Meters with Capacity of 250 CFH or Less (Class 1)	178,703	$12,771,575.58	$71.47
Group B	Meters with Capacity of Greater Than 250 CFH and Less Than or Equal to 450 CFH (Class 2)	5,412	$783,564.00	$144.78
Group C	Meters with Capacity of Greater Than 450 CFH			
	(Class 3)	1,335	$972,082.36	$728.15
	(Class 4)	682	$627,292.63	$919.78
	(Class 5)	483	$284,647.21	$589.33
	(Class 6)	356	$389,827.03	$1,095.02
	(Class 7)	287	$163,227.72	$568.74
	(Class 8)	195	$264,219.70	$1,354.97
	(Class 9)	733	$1,119,758.42	$1,527.64
	(Classes 3 - 9)	4,071	$3,821,055.07	$938.60
Total		188,186	$17,376,194.65	$92.34

Number of Customers:

Residential	154,661
Commercial	19,084
Industrial & Interr. < 1,000 Contract Demand	352
Sub-total	174,097
Industrial & Interr. > 1,000 Contract Demand	30
Total	174,127

Assumptions

1. All Residential Meters are in Group A
2. All Industrial Meters are in Group C
3. The average value for Industrial Meters is based on Class 9 Meters
4. Commercial Meters fall into all three Groups
5. Customers with Daily Contract Demands in excess of 1,000 do not have meter investment in Account 381
6. Meters in Inventory are in proportion to Meters in use

WESTERN KENTUCKY GAS COMPANY
METER ANALYSIS
September 1994

Analysis:	(a)	(b)	(c)	(d)
Meters		188,186		
Net Customers		174,097		
Ratio of Meters to Customers		108.09%		

Meter Allocation:

	Total	Residential	Commercial	Indus/Inter.
Net Customers	174,097	154,661	19,084	352
Meters				
Group A	178,703	167,173	11,530	
Group B	5,412		5,412	
Group C	4,071		3,691	380
Total	188,186	167,173	20,633	380

Meters - Gross Plant Value:

	Total Meters	Total Investment	Invest. Per Meter
Group A	178,703	$12,771,575.58	$71.47
Group B	5,412	$783,564.00	$144.78
Group C -Comm.	3,691	$3,240,551.87	$877.96
Group C -Ind./Inter.	380	$580,503.20	$1,527.64
Total	188,186	$17,376,194.65	$92.34

Gross Plant Value Allocation:

	Total	Residential	Commercial	Industrial
Group A	$12,771,903.41	$11,947,854.31	$824,049.10	
Group B	$783,549.36		$783,549.36	
Group C -Comm.	$3,240,550.36		$3,240,550.36	
Group C -Ind./Inter.	$580,503.20			$580,503.20
Total	$17,376,506.33	$11,947,854.31	$4,848,148.82	$580,503.20
Meters	188,186	167,173	20,633	380
Investment/Meter		$71.47	$234.97	$1,527.64
Relative Investment		1.0	3.3	21.4

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, h
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

h. An adjustment for customer accounts was incorporated into the model. Explain why this was the only adjustment other than the adjustment to normalize weather incorporated into the model.

Response:

Forecasted test year information was not fully available at the time the class cost-of-service study was prepared. Therefore, the study was prepared using the most recent fiscal year data available. Since the primary objective of the study was to distribute the Company's fiscal 1998 costs among customer classes in a reasonable manner and not to determine an overall proforma revenue requirement, the only adjustments to per books data that were included were adjustments that could materially affect the relative level of costs among customer classes.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item Question 47, i
Witness: Thomas H. Petersen

Data Request:

47. Refer to the Application, Volume 2 of 10, the Testimony of Thomas H. Petersen and Volume 9 of 10, Tab 3, the class cost-of-service study.

i. Notes are included in many pages of the study describing rules, actions or assumptions applied to the particular worksheet. Provide a narrative description of these rules and actions and the source of the assumptions.

Response:

The notes on page 3 of the study generally describe how each rate base item was assigned to a function. Some notes provide information about the source of the data. For example footnote 4 indicates a 12 month average balance. The assignments were done in the same way as in previous studies filed with the Commission. Work in progress (note 2) was all assigned based on gross plant percentage. Prepaid gas purchases (note 4) was all assigned to gas cost. Customer advances and materials and supplies (notes 6 and 7) are mostly related to distribution facilities, with some related to transmission plant. This is reflected in the 95 percent allocation of customer advances, materials and supplies to the distribution function with the remainder to the transmission function.

The notes on pages 4, 6, 8, 10, 12 and 14 generally describe how each item was classified. Some notes provide information about the source of the data. The classifications were done in the same way as in previous studies filed with the Commission. The 50 percent demand, 50 percent commodity split for most storage items reflects the dual use of storage to help meet peak day requirements and to reduce seasonal differences in purchases. Gas Cost administrative costs, excluding commodity prepayments were generally considered to be demand related. Distribution expense accounts 878, 879, 880, 892, 893 and 894 primarily relate to meters and other customer premises costs and so were classified as customer related. Transmission and production costs were generally considered to be demand related.

The notes on page 16 define or describe the term they are applied to. For example, note 2 defines Winter Period as November through March. The notes on sheet 1 explain two calculations that would not otherwise be disclosed on this page. The notes on sheet 8 list the assumptions used to facilitate the analysis of readily available data on meter investment. The meter analysis determines the relative meter investment by customer class that is used in CUST-D and CUST-M allocators on page 16. These assumptions were made by Mr. Petersen after consultation with other company personnel.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 48
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Rate G-1 and G-2. Why is there no page reference for: (1) the Weather Normalization Adjustment; (2) the Gas Cost Adjustment Rider; and (3) the Margin Loss Recovery Rider? Does Western agree that including page references for each of these items would enable the tariff reader to better follow the tariffs without being required to constantly refer to the tariff index?

Response:

The side by side comparison of tariff sheets 11 (Rate G-1) and 17 (Rate G-2) demonstrate that Western had not previously used a format which identified a page reference for items such as the Gas Cost Adjustment in its current tariff. Consequently, Western applied the same format for listing all of the components which would be applicable in the determination of the G-1 and G-2 Rates, including (1) the Weather Normalization Adjustment; (2) the Gas Cost Adjustment Rider; and (3) the Margin Loss Recovery Rider.

Western has no objection to including a page reference for each of these items, and agrees that such references would make the tariff easier to follow.

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Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 26, Weather Normalization Adjustment Rider ("WNA").

a. The tariff shows an effective date of July 24, 1999, while page 37 of the Testimony of Gary L. Smith indicates the WNA would go into effect November 1, 2000. What is the correct effective date for the WNA?

b. The tariff states "Base loads and heating sensitivity factors will be determined by class and computed annually." Provide a detailed description of how base loads and heating sensitivity factors will be determined. Include example calculations if necessary.

c. Page 38 of the Testimony of Gary L. Smith sets out a proposed schedule for filing periodic reports with the Commission. Should the schedule and a description of these reports be included in the tariff? Why or why not?

Response:

a. Although it is unclear in the proposed tariff, at Sheet No 26, Western's proposal is to implement the Weather Normalization Adjustment beginning November 1, 2000. Western agrees that this implementation date should be clarified in the proposed tariff.

b. The annual computation of class base loads ("BL") and heating sensitive factors ("HSF") closely parallels the process utilized for the weather normalization adjustment, set forth in EXHIBIT GLS-4, in Volume 2 of 10, Tab 11 of the Application.

The annual computation of these factors would be completed prior to November 1 of each year, based on a twelve month period ending August 31. Exhibit GLS-4, Schedule 3 of 5, provides an example of this process for the residential class (with the minor exception that this Exhibit uses a twelve month period through September, instead of August). Referring to this Exhibit, note that the BL (line 14, column e - referred to as the "constant") is calculated based on the average customer usage during the summer months of July and August. In

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this case the BL equals 1.5444 Mcf per month. The HSF (column c - referred to as the "coefficient") is calculated based on the annual heating Mcf for the class divided by the actual heating degree days. In this case the HSF equals 0.0155 Mcf per degree day.

To provide an example of the calculation using the equation noted in the proposed tariff, we will utilize these BL and HSF factors applied to November 1997 data included in Exhibit GLS-4. This example is based on a residential customer whose billing cycle is November 1-30, 1997. Other key variable in the equation are:

- Normal Degree Days ("NDD") for 11/1-11/30 = 520 (reference GLS-3, Schedule 2 of 5).
- Actual Degree Days ("ADD") for 11/1/97-11/30/97 = 658 (reference GLS-3, Schedule 2 of 5).
- Distribution Charge ("R") for Residential Class = \$1.0615 (reference current tariff rate schedule).

$$WNA_{residential} = R \frac{(HSF \times (NDD - ADD))}{(BL + (HSF \times ADD))},$$

$$WNA_{residential} = \$1.0615 \frac{(0.0155 \times (520-658))}{(1.5444 + (0.0155 \times 658))},$$

thus, the residential WNA factor for the referenced billing cycle in this example would be:

$$WNA_{residential} = (\$0.1933) \text{ per Mcf}$$

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c. Western proposes to submit the monthly reports, summarizing the WNA effect on customer bills by cycle for each customer class as well as the actual and normal degree days in each cycle, as set forth in the referenced testimony. If the Commission would like Western to put the proposed schedule for reporting of these details in the proposed WNA tariff, we would have no objection.

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Witness: Smith

Data Request:

At page 37 of the Testimony of Gary L. Smith he states that the proposed WNA mirrors that of Western's affiliate, United Cities Gas Company. Provide for the last three years (fiscal or calendar), a comparison of United Cities' residential revenues both with and without the impacts of its WNA.

Response:

	United Cities Gas Residential Revenues With WNA	United Cities Gas Residential Revenues Without WNA
FY96	$75,217,538	$77,489,090
FY97	$79,231,951	$77,174,469
FY98	$85,109,110	$84,598,930

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DR Item 50 a & b
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 27, Gas Cost Adjustment Rider ("GCA").

a. Since the proposed GCA is zero-based, is it still necessary that Western file its GCA on a monthly basis?

b. Explain in detail why quarterly GCA filings, as submitted by Kentucky's other major LDCs, would not be sufficient to meet Western's gas cost recovery needs.

Response:

a. Western's original reasoning for filing its GCA's on a monthly basis was: 1) to assure responsiveness to volatile market gas price swings, and, 2) provide for a more accurate reflection of gas costs in our sales rates to avoid sending false pricing signals to T-2 transportation customers, who have the option to either transport or utilize Western's sales service. Western's proposal to adopt a zero-based GCA does not affect the above-stated factors.

b. Although not a consequence of our zero-based GCA, Western would certainly reconsider the frequency of our GCA filings. Since implementing the monthly frequency in early 1994, the volumes of T-2 service have declined dramatically. A vast majority of Western's current transporters utilize carriage services T-3 or T-4, no longer retaining the option to swing from sales to transportation service and then back again. Western still, however, desires to responsively track the changes in gas supply costs in our GCA. Western has no objection to filing quarterly GCA's as a general practice, but would prefer to retain the flexibility to file more frequently, from time to time, to respond to significant gas supply cost changes.

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DR Item 51
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 291, the Margin Loss Recovery Rider ("MLR").

a. The tariff does not specify this, but the Testimony of Gary L. Smith, at page 29, indicates that the proposal will shift lost revenues to sales customers. Why is the proposed shift to sales customers only? Explain how the proposed 90 percent / 10 percent sharing between customers and the company was developed.

b. The MLR tariff does not specify the rate schedules to which it would be applied. Was this an oversight or was it done intentionally? Explain why an "Applicable" provision designating the appropriate rate schedules should not be included in the tariff.

c. How was it determined that the MLR should be adjusted on a semi-annual basis, as opposed to monthly, quarterly, or annually?

Response:

a. Western proposes to apply the MLR equally, on a per Mcf basis, to each of its sales services (Rates G-1, G-2, LVS-1 and LVS-2). Western proposed to exclude transportation services, recognizing that applying this additional component could contribute to further pricing difficulties in the competitive large industrial transportation market.

As stated in testimony, Western proposed this sharing ratio, absorbing 10% of the revenue reduction, as a continued assurance that Western would maximize contract revenues through the highest possible negotiated price. Testimony also referenced that another Atmos business unit has similar mechanisms in place in Tennessee, Georgia and South Carolina. The respective sharing ratios (customers/company) in these jurisdictions are: 90/10, 75/25 and 100/0.

b. Although the proposed tariff, at Sheet 29L, does not clearly state that the MLR applies to the margins for sales services, each of Western's sales services (Rates G-1, G-2, LVS-1 and LVS-2), do include a reference to the Margin Loss Recovery Rider as a component of the rate. Western agrees that including an

"Applicable" section designating the sales rate schedules to which the rider is applied would be a beneficial cross-reference.

c. The proposal synchronizes the filing of the MLR with the semi-annual updates of Western's GCA Correction Factor. Western does not anticipate that distribution charge losses recovered through this rider will exhibit any extreme variability; therefore, we felt that filings more frequent than semi-annually would be unnecessary. Extending the filing frequency to longer periods than we proposed, say annually, would merely serve to delay the responsiveness of the recovery mechanism.

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DR Item 52 a
Witness: Hack

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 30d, Gas Research Institute ("GRI") R & D Rider.

a. The unit charge in the tariff is proposed to be billed "according to the transition schedule outlined in the pipeline's tariffs." Provide the transition schedules for each of the pipelines serving Western.

Response:

The attached GRI Surcharges schedule was obtained from Texas Gas Transmission. The FERC established the same schedule for all pipelines, although the pipelines may, of course, apply different rates within that schedule.

TEXAS GAS TRANSMISSION

GRI Surcharges

	1998	1999	2000	2001	2002	2003	2004
Commodity (Cents/MMBTU)	0.88	0.75	0.72	0.70	0.50	0.40	0.00
High Demand (Monthly Cents/MMBtu)	26.00	23.00	20.00	9.00	6.00	5.00	0.00
Low Demand (Monthly Cents/MMBtu)	16.00	14.20	12.30	5.50	3.70	3.10	0.00
Small Customer Surcharge (Cents/MMBtu)	2.00	1.80	1.60	1.10	0.80	0.60	0.00
One - Part Surcharge (Cents/MMBtu)	1.70						

Converted from Cents/MMBtu to $/MMBtu, and on a Daily basis for the Demand Charges

	1998	1999	2000	2001	2002	2003	2004
Commodity ($/MMBTU)	0.0088	0.0075	0.0072	0.0070	0.0050	0.0040	0.0000
High Demand (Daily $/MMBtu)	0.0085	0.0076	0.0066	0.0030	0.0020	0.0016	0.0000
Low Demand (Daily $/MMBtu)	0.0053	0.0047	0.0040	0.0018	0.0012	0.0010	0.0000
Small Customer Surcharge ($/MMBtu)	0.0200	0.0180	0.0160	0.0110	0.0080	0.0060	0.0000
One - Part Surcharge ($/MMBtu)	0.0170						

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Witness: Smith

Data Request:

b. What was Western's "level of contribution per Mcf" as of December 31, 1998?

Response:

Pipeline	Rate per Mcf Daily Basis	Description
Texas Gas Transmission	$0.0000	(Fully discounted)
Trunkline Gas Company	$0.0000	(Fully discounted)
Tennessee Gas Pipeline	$0.0200	(Small Customer Surcharge)
Midwestern Gas Transmission	$0.0088	(Commodity)
	$0.0085	(High Demand Rate)
	$0.0053	(Low Demand Rate)
ANR Pipeline	$0.0088	(Commodity)
	$0.0085	(High Demand Rate)

Note 1: Level of contribution per Mcf is pipeline specific and subject to related pipeline volumes only.

Note 2: Demand Rate per Mcf is applied to reserved quantity only.

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DR Item 52 c & d
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 30d, Gas Research Institute ("GRI") R & D Rider.

c. Why is the proposed tariff rider to be "applicable to all gas transported by the Company other than Rate T-3 and T-4 Carriage Service"?

d. Does "all gas transported" mean sales and transportation volumes or transportation volumes only? Explain why it should be one or the other.

Response:

c. Carriage services (Rates T-3 and T-4) do not utilize Western's interstate pipeline capacity or rely upon our commodity deliveries through the interstate pipelines. Since the GRI R&D surcharge is, historically and currently, a component of gas cost from the interstate pipelines, these services have not borne any of these costs through Western's Gas Cost Adjustment ("GCA"). Western's intent is to continue to collect GRI charges from the same services that have historically contributed to the charges and not impose an increased cost of service to any tariff service as of the GRI R&D funding changes. Therefore, the "exemption" of Rate T-3 and Rate T-4 Carriage Services from GRI charges merely recognizes that these services have not borne these costs through Western's GCA.

d. "All gas transported" means all sales and transportation volumes. As stated in the response to part c. of this data request, Western's intent is to continue to collect GRI charges from the same services that have historically contributed to the charges.

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DR Item 52 e
Witness: Smith

Data Request:

Identify any other methods of GRI cost recovery that Western considered and explain why those methods were not selected.

Response:

The only other means considered by Western was to continue the treatment of GRI R&D costs as a gas cost via the GCA. In the past, GRI costs had been flowed through as a mandatory component of pipeline transportation charges. However, more recent FERC action, partly in response to the pipelines' desires for more competitive pricing, allowed pipelines to discount their service by removing GRI R&D costs from their rates. Western's customers have been a beneficiary of such discounting. Over time, GRI R&D costs will be phased out of all pipeline charges and become a purely optional cost to LDCs. At a presentation by GRI at the KPSC in April, there was discussion that GRI R&D costs would be better collected as a component of transportation (distribution) service in light of the increasingly competitive retail gas market. The GCA is and will continue to be subject to increasing competition, putting greater pressure to eliminate components such as GRI costs. Recovering GRI R&D costs through Western's proposed distribution charges would ensure GRI a sounder source of R&D funding in the future. Hence, Western has proposed a multi-year transition of shifting GRI R&D cost recovery responsibility from the GCA to a rider applicable to Western's proposed distribution charges, mirroring the transition plan outlined by the FERC.

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DR Item 52 f
Witness: Smith

Data Request:

Identify the benefits that accrue to Western's ratepayers from Western's funding of GRI's R & D activities.

Response:

See enclosed document entitled "Benefits of GRI R&D Results That Have Been Placed in commercial Use in 1993 Through 1997."

GRI-98/0147

Benefits of GRI R&D Results That Have Been Placed in Commercial Use in 1993 Through 1997

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May 1998

Abstract

This report provides a brief description of the twenty-seven new GRI R&D items introduced in 1997 and quantifies the economic benefits of one hundred and eleven items commercialized between 1993 and 1997 that are known to have produced significant economic benefits for their users. The calculated ratio of the benefits to gas customers to total GRI costs incurred in 1993 through the end of 1997 was 9 to 1.

In a similar analysis carried out in 1997 for ninety-seven R&D items placed in commercial use between 1992 and 1996, the calculated ratio of the benefits to gas customers to total GRI costs incurred during the same period was 7.1 to 1.

Legal Notice

Acknowledgments

The authors gratefully acknowledge the significant contribution provided by the following personnel of the Energy Resources Center of the University of Illinois at Chicago: Irene D. Banas for evaluating the benefits of GRI's Supply and Environment and Safety R&D; Dr. Paul L. Brillhart on his analysis of the Basic Research, Industrial, and Power Generation R&D benefits; David A. Eslinger on his analysis of the Residential and Natural Gas Vehicles R&D benefits; and Darryl M. Lang on his analysis of the Distribution and Transmission R&D benefits.

Also, we want to thank the GRI personnel for their continued support in the evaluation of benefits from GRI R&D results.

Introduction

Between January 1, 1997 and December 31, 1997, twenty-seven GRI R&D results were placed in commercial service. In addition, enhanced versions of four previously commercialized items were placed in use. Those items are listed in Table 1, and brief descriptions of the 31 items are included in Appendix A. With these new additions, some 165 GRI R&D results have entered the commercial marketplace during the 5-year period between January 1993 and December 1997. The full list of the 165 items is included in Appendix B. As one measure of the value of the GRI R&D program, the economic benefits accruing to users of 111 out of the 165 products can be compared to the total outlays of GRI during the past five years. This paper highlights the new GRI products that have entered the market during the past year and presents the results of the benefit-to-cost analysis of GRI's R&D results during the past five years.

Notable additions to the list of GRI R&D results placed in commercial service in 1997 are the introduction of a new residential water heater for outdoor installation; the introduction of a new engine-driven chiller with a footprint equivalent to the electric competition; a new gas refrigeration system; equipment and software that improve refueling for natural gas vehicles; the application of low emission combustion systems for power generation; a new system that can significantly cut the cost of determining the effectiveness of cathodic protection systems for steel piping used to transport gas; an innovative, time and money-saving trenchless technology for renewing gas service lines; guidelines for directional drilling used by gas utilities to install polyethylene pipe; information on the potential health risks associated with PCB (polychlorinated biphenyls) releases from pipelines; a research program to develop and evaluate an integrated chemical-biological treatment process capable of enhancing the rate and extent of polynuclear aromatic hydrocarbons; a testing method for identifying important resin failure characteristics in plastic pipe; atlases of natural gas and oil reservoirs for the Appalachian Basin and for deep water drilling in the Gulf of Mexico; a manual about underbalanced drilling; and an improved analysis protocol for determining the reservoir parameters used for calculating the gas-in-place volume of coalbed reservoirs.

Table 1. GRI R&D Results That Have Been Placed in Commercial Use in 1997

RESIDENTIAL

1. Outdoor Gas Water Heater (American Water Heater Co.)
2. Advanced Gas Fireplace (Lennox)

COMMERCIAL

3. BinMaker™: The Weather Summary Tool
4. TecoFROST™ Gas Engine Driven Refrigeration
5. York Millennium™ GED, Model YB
6. Pulse-Combustion Hydronic Boiler*

TRANSPORTATION

7. FuelMaker-Quantum Vehicle Refueling Appliance Line
8. AccuFill Dispenser Fill Algorithm
9. NGV-1 Receptacle/Nozzle Standard Design

POWER GENERATION

10. Allison LE IV Dry, Low-Emissions (DLE) Combustor*
11. General Electric LM 1600*

GAS OPERATIONS

12. Orifice Meter Information*
13. Pipeline Current Mapper
14. RENU Service Renewal Technology
15. Pneumatic Tool Diagnostic System (Tool Tester)
16. Horizontal Directional Drilling Guidelines
17. Hydrostatic Test Water Discharge
18. PCB Contaminated Pipeline Abandonment Protocol
19. Low Cost Method for Formaldehyde Measurements
20. Contained Recovery of Oily Waste Technology Evaluation (CROW) Technology for Water Cleanup
21. CBT (Chemical-Biological Treatment) Cleanup Technology
22. Gas Plant Emissions/Efficiency Report
23. Lomic SonicWare™
24. Plastic Pipe Reliability (PENT Test)

SUPPLY

25. Mercury Soil Contamination Program
26. Offshore Atlases - Part 2
27. Appalachian Atlas
28. Underbalanced Drilling Manual
29. Freeze/Thaw for Production Water
30. Glycol Dehydrator Controls/Monitoring
31. Coalbed Reservoir Gas-In-Place Analysis Short Courses

* Enhancement to a previous winner.

Benefits Results

The full list of the 165 items placed in commercial use between January 1993 and December 1997 is included in Appendix B, but we chose to focus the benefits analysis of GRI's R&D on 111 of the 165 items that are known to have produced significant *economic* benefits for their users. The 111 items are listed in Table 2. Benefits to product users in typical applications were calculated by comparing the economics of the GRI-sponsored products with the economics of products that would have been used in the absence of the GRI product. Product cost and performance data were obtained from product vendors, from field test results, or from product users. The measure of product benefit is the net present value of the incremental cash flow to the user (cost savings minus incremental cost) over the product lifetime using a real discount rate of 5% (above inflation). The GRI Baseline [1] national average projections of energy prices were used, when appropriate, to estimate cost savings. Total benefits were calculated by multiplying the unit benefits by the sales projected by product vendors from the first year in which the product was sold through 2002. The results are shown in Table 2. A range of product sales is shown to protect proprietary vendor sales projections.

As shown in Table 2, calculated economic benefits for the 111 items are estimated to be between $7.2 to $14.0 billion. Table 3 shows the expected value of benefits, at about $9.75 billion, and the breakdown of the economic benefits by sector. We estimate that the 111 items account for most of the economic benefits that would be calculated for the entire set of 165 products. Omitted items often offer significant benefits to their users, but have not achieved widespread use as have the 111 high impact items. More importantly, many of the omitted items produce benefits that are not easily quantifiable in economic terms. For example, R&D related to natural gas vehicles has been undertaken primarily to provide a natural gas transportation option that meets existing or anticipated emissions requirements. Other R&D results provide test methods for new gas equipment. Finally, many of the 165 items provide information that is useful to the gas industry in developing the gas resource and in delivering it to the customer.

Table 2. Summary of Benefits of GRI R&D Results That Have Been Placed in Commercial Use in 1993 Through 1997

	Sales or Applications Projected Through 2002 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 1997$)		
RESIDENTIAL							
Protocol for Water Heater Emissions Measurement	10,000	to	30,000	1995	$11	to	$12
Gas Load Center	2,000	to	4,000	1995	$0.2	to	$0.4
Venting Products:	400,000	to	750,000	1995	$169	to	$318
• Venting Guidelines for 1996 National Fuel Gas Code							
• Test Protocols for High-Temperature Plastic Vents							
Carrier "Chimney Friendly" Furnace	5,000	to	15,000	1996	$2	to	$5
Modulating Furnace by RHEEM	30,000	to	100,000	1996	$0.2	to	$1
Empire Gravity Vented Wall Furnace	35,000	to	80,000	1996	$128	to	$293
Utility-to-Customer Communication (Whisper)	1,100,000	to	3,500,000	1996	$21	to	$66
Outdoor Water Heater	70,000	to	150,000	1997	$8	to	$16
COMMERCIAL							
Absorption Chillers (Trane)	500	to	1,000	1993	$261	to	$522
Gas Combination Oven/Steamer	750	to	2,000	1994	$47	to	$124
Large Gas Engine-Driven System:	270	to	740	1994/95	$69	to	$197
• 340RT Large Engine Chiller (Tecogen)							
• 485RT Large Engine Chiller (Tecogen)							
• 725RT Large Engine Chiller (Tecogen)							
• 1000RT Large Engine Chiller (Tecogen)							
• Millennium Engine-Driven Chillers (York)							
Batch Booster Water Heater	2,000	to	5,000	1995	$11	to	$27
Restaurant-Sized Steam Combination Oven	1,000	to	3,000	1995	$15	to	$46
GATC Quick Response Activities:	2,000	to	4,000	1995	$28	to	$55
• Gas Rotisserie Chicken							
Trane Modulating Rooftop Unit	2,000	to	5,000	1996	$8	to	$20
Separation Requirements in ASHRAE Standard 62-89R	20,000	to	35,000	1996	$202	to	$354
TecoFROST™ Gas Engine Driven Refrigeration	10	to	30	1997	$3	to	$8
Pulse Combustion Hydronic Boiler	150	to	400	1996	$0.5	to	$1.3
INDUSTRIAL							
DONLEE TurboFire® XL Boiler	12	to	25	1994	$9	to	$18
Ion-Nitriding GASFIRED™ Vacuum Furnace	4	to	9	1994	$3	to	$7
Process Application of Composite Radiant Tubes	15,000	to	30,000	1994	$27	to	$53
Heat Treat Furnaces	10	to	20	1995	$7	to	$13
Low NO_x Air Staging for Glass Melting	15	to	30	1995	$139	to	$278
Glass Tempering Furnace	20	to	40	1995	$61	to	$121
High Performance Infrared Burners	50	to	100	1995	$126	to	$253

	Sales or Applications Projected Through 2002 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 1997$)		
Steel Products Heating Furnace	7	to	11	1995	$200	to	$300
Industrial Boiler Gas Cofiring	90	to	200	1995	$47	to	$104
CYCLOMAX® Low NO_x Industrial Burner	200	to	350	1996	$145	to	$253
TRANSPORTATION							
Chrysler Minivan	900	to	1,500	1993	$0.7	to	$1.2
Caterpillar Dual-Fuel Truck Engine	500	to	2,000	1996	$5	to	$19
POWER GENERATION							
Low NO_x Turbine Combustors:	***			1995/97	$456	to	$786
* SoLoNO$_x$™ Gas Turbine Combustor (Solar)							
* Allison 501-K Low NO_x Combustor							
* Low- NO_x Turbine Combustor (GE LM 1600)							
GAS OPERATIONS							
Low NO_x Turbine Combustors:	***			1992/95	$1,199	to	$2,476
• SoLoNO$_x$™ Gas Turbine Combustor (Solar)							
• Dry Low- NO_x Combustor (GE)							
• Allison 501-K Low NO_x Combustor							
Visual Internal Inspection System	800	to	2,000	1993	$14	to	$34
Electrostatic Discharger System	20	to	50	1993	$15	to	$36
Compressor Diagnostic Software	25	to	50	1993	$6	to	$12
ENSYS Rapid Field Test Kit for PCB Soil Contamination	100,000	to	200,000	1993	$7	to	$14
Low-Cost NO_x Controls for Pipeline Engines:							
• Low-Cost NO_x Controls for 4-Cycle Ingersoll-Rand Pipeline Engines (Dresser-Rand)	***			1994	$37	to	$65
• Low-Cost NO_x Controls for 2-Cycle CLARK™ Pipeline Engines (Dresser-Rand)	***			1994	$30	to	$45
• Low-Cost NO_x Controls for 2-Cycle GMV Series Pipeline Engines (Cooper Industries)	***			1994	$3	to	$4
Electronic Flow Measurement Device	30,000	to	60,000	1994	$27	to	$53
LIFESPAN PE Program	100	to	200	1994	$61	to	$122
Excess Flow Valves Information	***			1985/94	$69	to	$104
Acoustic Pipe Tracer	250	to	550	1995	$3	to	$7
Relining of Cast Iron and Steel Pipe	7,000	to	15,000	1995	$17	to	$36
Coiled Plastic Pipe Information	***			1995	$16	to	$23
Guidelines for Low-Cost, OSHA-Approved, Shoring Design and Materials	***			1995	$15	to	$41
Plastic Pipe Across Bridges	5,000	to	12,000	1995	$32	to	$76
Soil Compaction Meter	4,000	to	8,000	1995	$3	to	$6
Inspection Vehicle for Unpiggable Lines	20	to	40	1995	$43	to	$86
OMNET Surface/Subsurface Modeling Software	40	to	80	1995	$64	to	$128
Methodology to Estimate Methane Emissions from Gas Operations (STAR Program)	10,000	to	20,000	1995	$37	to	$75

	Sales or Applications Projected Through 2002 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 1997$)		
Anaerobic Cast Iron Joint Repair Guide	50,000	to	120,000	1996	$20	to	$48
Assessment of Gas Pipeline Non-Destructive Evaluation (NDE) Technologies	***			1996	$55	to	$110
Airborne Pipeline Integrity Monitoring (APIM) Assessment	***			1996	$5	to	$11
Pipeline Inspection and Maintenance Optimization System (PIMOS)	***			1996	$11	to	$20
Remote and Automatic Controlled Valves Guidelines	***			1996	$38	to	$82
Risk Assessment/Risk Management Guidelines	***			1996	$80	to	$138
Third-Party Damage Prevention Assessment	***			1996	$20	to	$39
Carbon Monoxide Detector Supplemental Standards	20,000,000	to	40,000,000	1996	$279	to	$557
Manufactured Gas Plant (MGP) Site Management Guidebooks (4 Volume set)	200	to	500	1996	$29	to	$73
Cost Model for MGP Site Cleanups	150	to	300	1996	$17	to	$34
Soil Cofiring in Utility Boilers at MGP Sites	15	to	30	1996	$7	to	$13
Thermal Desorption for Soil Cleanup at MGP Sites	30	to	60	1996	$32	to	$64
Pipeline Current Mapper	2,000	to	4,000	1997	$41	to	$82
RENU Service Renewal Technology	25,000	to	50,000	1997	$23	to	$46
Pneumatic Tool Diagnostic System (Tool Tester)	100	to	200	1997	$18	to	$36
Hydrostatic Test Water Discharge	150	to	350	1997	$20	to	$46
PCB Contaminated Pipeline Abandonment Protocol	600	to	1,300	1997	$28	to	$61
Low Cost Method for Formaldehyde Measurements	1,000	to	3,000	1997	$10	to	$30
Contained Recovery of Oily Waste Technology Evaluation (CROW) Technology for Water Cleanup	20	to	40	1997	$7	to	$6
CBT Cleanup Technology	10	to	25	1997	$10	to	$25
Gas Plant Emissions/Efficiency Report	200	to	400	1997	$5	to	$9
Lomic SonicWare™	600	to	1,300	1997	$23	to	$50
Plastic Pipe Reliability (PENT Test)	400	to	800	1997	$9	to	$18
GAS SUPPLY							
Atlases Of Major Gas Reservoirs:	2,000	to	4,000	1989/97	$71	to	$142
• Atlas of Major Texas Gas Reservoirs				1989			
• Atlas of Major Central and Eastern Gulf Coast Gas Reservoirs				1993			
• Atlas of Major Mid-Continent Gas Reservoirs				1993			
• Atlas of Major Rocky Mountain Gas Reservoirs				1993			
• Appalachian Atlas				1997			
• Offshore Atlas				1997			
Gas Content Correlation for the Antrim Shale	2,000	to	3,000	1993	$255	to	$383

	Sales or Applications Projected Through 2002 (in units)			Year of First Sale	Net Present Value of Benefits** (Million 1997$)		
Amplitude Variation with Offset (AVO)	1,500	to	2,500	1993	$179	to	$299
Quantitative Gas Measurement (QGM)	6,000	to	10,000	1994	$22	to	$36
Wireless Telemetry Tool	400	to	700	1994	$10	to	$17
Software for Interpreting Old Electrical Survey Logs	500	to	1,500	1994	$2	to	$7
Produced Water Treatment Calculation Cost Model (ProWCalc)	150	to	250	1995	$8	to	$14
Successful Drilling Practices	1,000	to	2,000	1995	$85	to	$169
Eppendorf CS-200 Analyzer for Optimization of Amine Unit Operations	40	to	80	1995	$33	to	$66
CO_2 Membrane Database	150	to	250	1995	$2	to	$4
R-BTEX Emissions Control Process	800	to	1,600	1995	$104	to	$209
Secondary Gas Recovery, Gulf Coast and Mid-Continent	***			1995	$1,196	to	$2,016
Improved Coal Seam Gas Content Measurement Method (CoreGas Database)	100	to	200	1995	$9	to	$18
Fourier Transform Infrared Technique (FTIR) for HAPs Measurements	1,000	to	3,000	1995	$16	to	$48
GRI-HAPCalc Screening Tool	15,000	to	30,000	1995	$29	to	$57
Production Water/Waste Management and Site Remediation Treatment Technology Database, GRI-TTBD	300	to	600	1995	$3	to	$6
Chemicals Used in Gas Operations Database, GRIChem-USE	300	to	700	1995	5	to	11
Drilling Waste Atlas and Produced Water Atlas	200	to	400	1995	$13	to	$25
Scavenger CalcBase Database	15	to	30	1996	$42	to	$84
Title V Permitting Guidance	1,000	to	3,000	1996	$1	to	$4
Environmental Technology Information Center (ETIC)	20,000	to	50,000	1996	$2	to	$5
Granular Activated Carbon-Fluidized Bed Reactor (GAC-FBR)	5	to	10	1996	$4	to	$8
Emerging Resources in the Greater Green River Basin	1,000	to	2,000	1996	$194	to	$389
Underbalanced Drilling Manual	4,000	to	8,000	1997	$25	to	$51
Mercury Soil Contamination Program	100,000	to	300,000	1997	$147	to	$441
Glycol Dehydrator Controls/Monitoring	6,000	to	12,000	1997	$93	to	$186
TOTAL (million of 1997 dollars, 5% discount rate)					$7,238	to	$14,008

* Enhancement to a previous winner for a new market application.

** Net present value calculations based on a real discount rate of 5% (excluding inflation), stated in 1997 dollars.

*** Benefits are based on user feedback about technical and market influence of the group of the information items.

Table 3. Total Expected Benefits by Sector (Millions of 1997$)

• Residential	$478
• Commercial	$998
• Industrial	$1,024
• Transportation	$14
• Power Generation	$456
• Gas Operations	$3,976
• Supply	$2,804
TOTAL	$9,750

GRI R&D Costs

Between January 1993 and December 1997, GRI outlays totaled $925 million. For comparison to the R&D benefits calculated above, the cost cash flow stream was converted to an equivalent net present value lump sum expenditure at the beginning of 1997. As with the benefits calculation, a 5% real discount rate was used in the net present value calculation. The calculated equivalent cost was $1.08 billion. These costs include all outlays made by GRI during the past 5-year period, not just the costs incurred to produce the 165 R&D products. Consequently, a portion of the calculated cost will yet generate benefits as additional products are commercialized in the future.

Benefit-to-Cost Ratio

Dividing the calculated benefits by the costs results in a calculated benefit-to-cost ratio range of 6.7 : 1 to 13 : 1 (benefits of $7.2 to $14.0 billion divided by outlays of $1.08 billion) with an expected value of 9 : 1 ($9.75 billion divided by $1.08 billion). In a similar analysis carried out in 1997 for R&D items placed in commercial use between 1992 and 1996, the calculated ratio of the benefits to gas customers to total GRI costs incurred during the same period was 7.1 to 1 [Reference 2, "1997 Winners Analysis"].

Continuing Successes of GRI R&D Results Commercialized Prior to 1993

Although the focus of this analysis has been on GRI's most recent successes, several past successes continue to significantly impact the markets in which they are used. GRI is proud of the continuing success of these products, and we believe that a few comments about some of them are appropriate here.

Residential Space Heating. The residential space heating sector has long been a stronghold for natural gas. With approximately 50 million natural gas heated homes (51% of the market, [1]), gas furnace sales represented 84 percent of all furnaces shipped in 1997. In 1997 shipments of gas furnaces totaled about 2.8 million units [4]. GRI's R&D program in space conditioning had its first major success in the central furnace market with the introduction of the Lennox Pulse™ Combustion furnace in 1981. This furnace is one of the most efficient furnaces on the market today with a steady-state efficiency of 96%. Within two years of the introduction of the pulse combustion furnace, every furnace manufacturer introduced a condensing high-efficiency (over 90% AFUE) furnace in the market. However, several condensing furnace models experienced problems with the condensed vapor, causing corrosion of internal furnace parts. GRI sponsored research on condensing appliances to: (1) define the corrosion environment in condensing heat exchanger; and (2) evaluate materials for corrosion resistance in the condensing heat exchanger environment. Based on results from GRI's research, manufacturers responded quickly by redesigning these furnaces using corrosion-resistant materials. GRI's contribution in the development of the pulse combustion furnace and the materials research for condensing furnaces have significantly contributed to the development of the high-efficiency furnace market. According to the "Air Conditioning, Heating & Refrigeration News" (March 29, 1993, pp. 38-39), "The advent of the pulse combustion furnace more than a decade ago brought about a watershed in contractor marketing practices. A suggested installation price of two to three times that of an atmospheric gas furnace amused competitors --until it was proven that a substantial number of homeowners in colder climates were willing to scrap inefficient furnaces in good working order in order to gain fuel savings in the 50% range. Within two years, every furnace manufacturer was offering a condensing furnace line." In 1997, condensing furnaces captured about 25 percent of the gas furnace market.

Conventional gas furnaces have a long tradition of providing consumers with reliable, low-cost space heating and trouble-free venting. However, federal standards requiring a minimum 78% AFUE took effect in 1992. To increase efficiency, fan-assisted gas furnaces were developed that have lower flue-gas temperature, reduced air flow, and a combustion fan instead of a draft hood. Data from utilities and manufacturers indicate that these characteristics can increase condensation in venting systems designed for conventional atmospheric furnaces. High levels of condensation can cause premature corrosion in the vent and furnace, with associated repair costs. The need to prevent premature corrosion required changes in the recommended way of designing the vent system for most mid-efficiency furnaces. "The integrity of the gas industry within the residential market is at stake any time a significant change takes place which impacts the installation and proper operation of gas products," says Michael K. Barnett, Director of Planning & Residential Marketing, Alabama Gas Corporation (Alagasco). "Consumers will benefit from more efficient gas products, and it is the responsibility of our industry and our company to ensure that these products are installed properly and safely." GRI led an industry-wide effort to develop new venting guidelines for broad application. Through this Venting/Flue-Gas Management Project, recommendations for installation instructions and vent sizing tables were developed and disseminated to manufacturers for inclusion in all shipments of mid-efficiency fan-assisted gas furnaces. "GRI and the members of the Venting/Flue-Gas Management Project provided a non-judgmental technical forum within which the manufacturers could participate and learn," says William J. Thomaston, Director, Technical Assistance, Marketing, Alabama Gas Corporation. "This was no small accomplishment, due to the intense competition which exists within this increasingly consolidated industry." As a result of the GRI-led effort, new venting systems are properly sized for today's mid-efficiency fan-assisted furnaces and natural gas continues to be a safe, economical resource for meeting residential energy needs.

High Temperature Industrial Burners. High temperature industrial burners are employed by manufacturers in hundreds of different types of furnaces, ovens, reactors, kilns, and incinerators. Because of the great diversity of applications, process heating represents the industrial sector's most technologically complex market segment. In 1989, total energy consumption by manufacturers for process heating accounted for over 4.3 quadrillion BTU, with natural gas accounting for nearly one half or 2.2 quadrillion BTU. GRI pursues technological developments that will maintain gas as a cost-effective option for process heating and keep gas-based technologies abreast of current standards of convenience, performance, and environmental impact. For some applications the advantages of electrotechnologies --precise control, higher temperatures, and enhanced process capabilities-- are becoming important enough to offset their traditional disadvantage of high operating cost. The R&D challenge for the natural gas industry is to identify and develop new, high-temperature, precision control technologies that exploit the qualities and capabilities of natural gas in order to provide a performance premium when using natural gas. Path-breaking R&D efforts in ceramic burner development and burner control technologies have since led to component, equipment, and process innovations in the high temperature market. Technologies include the Pyrocore® Burner, Regenerative Burner with Integral Heat Recovery, NO_x Control for Glass Furnaces, Single-Ended Radiant Tube Burners, Industrial Fluid Heater, High Temperature Integral Quench Furnace, Vacuum Furnace, Ceramic Radiant Tubes, and a high-level gas injection process for blast furnaces. Advanced gas heat-treating technology, like the high efficiency TwinBed™ Burner developed by North American Manufacturing Company, has convinced some high volume customers to stay with natural gas. The TwinBed regenerative burner, developed with GRI R&D funding, permits the manufacturer to use an alternate fuel, but performs best with natural gas. The system consists of a compact regenerative heat exchanger to preheat combustion air, with a pair of burners that take turns firing and recovering heat. In 1993, the TwinBed burners accounted for approximately 38 Bcf of gross gas load. TwinBed burners have also been used with indirect-fired metallic radiant tubes, which heat products without exposing them to combustion gases. Inland Steel Company has seen fuel savings in excess of 45 percent when compared with the use of direct-fired burners and has not adopted the competing electrotechnology.

Blast Furnaces. Due to environmental regulations imposed on the pollutant emissions from coke ovens, metallurgical coke is increasingly scarce and expensive. In conjunction with this, the renewed steel demand has strained the productive capacity of the current blast furnace population. These two factors have poised the blast furnace industry to look for alternate fuel sources to decrease costs and increase productivity. The advantages of using high levels of natural gas include: reduced coke usage, improved furnace stability, increased iron-making productivity, lower operating costs, high quality (lower sulfur content) hot metal product, lower air pollution emissions, and gas-injection equipment has lower capital costs than pulverized-coal or oil-injection equipment. For over 25% of blast furnace coke requirements, high-level gas injection is an attractive substitute. However, there was insufficient information to determine the upper limit of natural gas injection to maximize its benefits. GRI and Charles River Associates have demonstrated the technical and operational value of using natural gas injection at high levels on blast furnaces. GRI supported the use of natural gas injection at high levels at Acme Steel Company, which has the last operational blast furnace in Chicago. Acme increased its rate of natural gas injection to 260lb/THM while it realized a production increase of 30%. Also, coke consumption went down by 30%. "The blast furnace ran very smoothly, and the hot metal chemistry remained right on target, allowing us to reach previously unattainable production levels," said Frank Gambol, Acme Steel Division Manager of Blast Furnaces. One of the major advantages of using natural gas as an injection fuel is its high hydrogen content which is very efficient at reducing the iron ore. Information and guidelines developed for the use of high level of natural gas in blast injection furnaces are refined and made available to iron and steel manufacturers throughout North America. Over the past decade, gas use has increased dramatically, growing from 38 Bcf in 1987 to 106 Bcf in 1995.

Natural Gas Vehicles. Vehicular transportation applications use large quantities of liquid fuels and are a major source of urban air pollution. There is a broad and increasing support for greater use of clean, alternative transportation fuels, such as natural gas. Approximately 63,000 NGVs were in use in the United States in 1996, virtually all in commercial fleets [3]. However, to attain a significant share of the transportation market, NGVs must overcome several technical and economic barriers. These barriers include the current range between refueling, an inadequate fueling station network, and the high capital cost premium of NGVs compared to liquid-fueled vehicles. GRI's objective is to develop and deploy NGVs and supporting infrastructure so that consumers can benefit from the economic, environmental, and energy security value of natural gas. Currently, several technologies developed with GRI funding are commercially available, including heavy- and medium-duty engines by Detroit Diesel Corporation and Cummins Engine Company, a light-duty CNG van by Chrysler Corporation, a dedicated natural gas passenger vehicle (Ford Crown Victoria), and a Qualified Vehicle Modifier Program (QVM) by Ford Motor Co. in which qualified outside companies convert Ford vehicles to operate on gas in selected markets. In 1996, new gas engines serving the medium- and heavy-duty fleet vehicle markets were introduced by Cummins Engine Company and Detroit Diesel Corporation. Also, John Deere Company, Caterpillar Inc., and Mack Trucks, Inc. entered the NGV market and Ford introduced dedicated gas-powered Vans and Pickups originally offered as QVM bifuel vehicles. In addition, GRI conducts studies to improve the performance and durability of natural gas engines. GRI's general strategy is to lead in technical development, innovation, and deployment of NGVs by addressing the following issues: the vehicle range and capital cost by developing innovative, lighter, and less expensive fuel storage systems; the fueling infrastructure; support quality bifuel conversion in the near term; develop efficient, dedicated OEM engines in the long-term; facilitate commercialization of NGVs through coordination with GRI member companies, manufacturers, and other organizations; pursue deployment of NGV technologies through various means including extended field tests; and provide safety research data as necessary to facilitate the regulatory process.

Advanced Stimulation Technologies (AST). GRI's AST program encompasses multiple technologies such as: quality control; stress profiling; and a 3-D modeling software program (FRACPRO™). These various stimulation techniques aid producers in optimizing the hydraulic fracture design and executions. FRACPRO was developed to estimate total fluid and sand needed to generate cost effective fracture treatments while enhancing ultimate production. An engineer can design, analyze, and evaluate the success of fracture treatments so that more gas can be recovered from tight sands and other low-permeability formations. Main benefits involve increased gas production and/or decreased fracture treatment costs. In the early 1980s, Gas Research Institute began a comprehensive research effort to evaluate and enhance technologies associated with hydraulic fracturing. Through a series of cooperative research and Staged Field Experiment wells, GRI collected evidence that challenged traditional hydraulic fracturing methodologies and theories. By analyzing detailed reservoir data and real-time fracture treatment data, new insights into the fracturing process were gained, and critical factors associated with successful fracture treatments were identified. These insights formed the core of GRI's ongoing AST deployment program. Although there are many interrelated concepts in the AST approach, all involve the acquisition and analysis of data in real time to improve fracturing results. The primary elements of AST include: onsite treatment quality control; pretreatment stress profiling and the use of 3-D fracture models; fracture treatment pressure history matching (in real time or offsite); and performing fracture treatment diagnostics on location to identify well-specific fracturing mechanisms (near-wellbore tortuosity, multiple fracture creation, etc.). As part of the AST deployment project, GRI developed a Communication Tool Kit that explains the methodology and technologies within AST. This Tool Kit is available to industry and includes a new 38-minute video introduction to AST, concise technology descriptions of key AST elements, and an eight-part training manual with more than 500 slides, sufficient for over 30 hours of instruction. Short courses and in-house GRI training programs are being used to increase the number of producing and service company personnel using AST on a regular basis. The rapid adoption of these technologies will help the industry develop more gas reserves, more quickly and at lower cost.

Conclusions

GRI's planning and budget allocation process strives to put in place a program with the maximum ratio of benefits to R&D costs for the mutual benefit of the gas customer and the gas industry. The economic evaluation of GRI's commercially successful R&D results have consistently shown that benefits far exceed the costs of the R&D program.

Analysis of the benefits of approximately 111 of the 165 GRI R&D items placed into commercial service between January 1993 and December 1997 shows that GRI R&D will return about $9 for every dollar invested in GRI during the same period. In addition to the fact that only portion of GRI's commercialized R&D items are included in the benefits calculation, all of the costs of GRI's operations during the 1993 to 1997 period have been included in the calculation of the benefit-to-cost ratio.

References

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Appendix A
GRI R&D Results That Have Been Placed in Commercial Use in 1997

RESIDENTIAL

Outdoor Gas Water Heater. American Water Heater Company has developed the Weather-Pro water heater, a residential/light commercial gas unit designed for easy outdoor installation and low operating costs. Currently, most gas-fired water heaters are installed indoors in basements, closets or garages. In warm regions of the country, many buildings do not have basements, so indoor water heaters occupy valuable living area or commercial space. While outdoor installation eliminates the need for venting, chimney paths and drip pans, until now gas water heaters could be installed outdoors in mild climates only if protected by a shed. The Weather-Pro's tough construction allows customers in warm regions to place the unit outdoors without a costly protective enclosure. In addition, the Weather-Pro requires no electrical hookup, thus reducing installation costs and enabling operation during power outages. The Weather-Pro has an input of 50,000 Btu/hr, enough for small commercial users, compared with an average of only 15,354 Btu/hr for standard residential electric water heaters.

Advanced Gas Fireplace. Lennox Industries has introduced a new enhanced gas fireplace to complement their extensive product line of gas hearth appliances. The result of extensive consumer research and comparisons of existing technologies, the Advanced Gas Fireplace combines the most popular product and safety features. Innovative burner port design and materials enhance flame realism and reduce emissions. The new fireplace also employs an advanced control system accessed by a wall-mounted remote control. Its modular design ensures easy installation and servicing while interchangeable log assemblies provide a range of aesthetic options. The Lennox fireplace represents the next generation of hearth products in the fastest growing segment of the residential natural gas appliance market. In addition to the product enhancements for Lennox, the generic burner design guidelines for improved efficiency and realism will be available to any gas hearth product manufacturer.

COMMERCIAL

BinMaker™: The Weather Summary Tool. BinMaker™ software tool, developed by GARD Analytics, Inc., Quantitative Decision Support, Linric Co., and Bluejay Software Associates, upgrades bin energy analysis by creating a wide range of accurate summaries of U.S. hourly weather data for 239 locations. Weather data files used by BinMaker are based on the TMY-2 (Typical Meteorological Year) data produced by the National Renewable Energy Laboratory in Golden, CO. The files reflect typical weather for all 8760 hours per year at 239 locations. They contain actual weather observations rather than smoothed or adjusted data, ensuring of a good presentation of weather behavior in the real world. The resulting electronic file can be exported for use in spreadsheets or other computer analysis programs. BinMaker CD-ROM-based program runs under Windows® 95 or 3.1. Among its other features, BinMaker avoids the error of underestimating loads associated with coincident variables by creating a joint-frequency table of hours at each combination of temperature and humidity.

TecoFROST™ Gas Engine Driven Refrigeration. GRI has formed a partnership with two divisions of ThermoPower Corporation—Tecogen, which markets TECOCHILL® gas engine-driven chillers, and FES, which manufactures packaged refrigeration compressors and TECOCHILL units—to develop the TecoFROST™ refrigeration system. The TecoFROST system, manufactured by FES and marketed by Tecogen, utilizes the same reliable refrigeration components - screw compressor, oil separator - as electric refrigeration systems manufactured by FES. The electric motor is simply replaced by a more efficient natural gas engine, the TecoDrive 7400, an industrial version of the General Motors 7.4-liter V8, which was developed with GRI support. Because the engine operates at variable speeds (ranging from 2000 to 3000 rpm), the system can follow refrigeration loads more closely than an electric motor, which optimizes energy consumption. The control panel on the TecoFROST features precise and efficient operating control to ensure high reliability. It also features a Remote Monitoring Control System (RMCS) for off-site monitoring and trouble-shooting. The TecoFROST uses non-CFC refrigerants (R-717 or R-22). The TecoFROST system is available for refrigeration applications as low as -70°F and up to 45°F. Sizes range from 100 to 150 hp (up to 140 tons). Tecogen is currently designing larger systems with capacities of 200-500 hp. Low emission packages are available as an option to meet all local emissions standards. Other options include engine jacket and exhaust heat recovery.

York Millennium™ GED, Model YB. York's Millennium™ line was developed by York and Caterpillar Inc. in partnership with GRI and was introduced in 1994. Millennium products are based on Caterpillar engines and York centrifugal compressors. The product line offers single-stage, centrifugal chillers with capacities from 400 tons to 2,100 tons, using HFC refrigerant 134a. The Millennium chillers have an exceptionally high part-load efficiency, a COP of 2.6 (highest heating value without heat recovery), and are supported by a York and Caterpillar service network. At the Gas Cooling Technology Conference & Expo in May, 1997, York unveiled a 400-ton gas-engine-driven (GED) chiller with a footprint equivalent to the electric competition. The YB model integrates an industrial-grade Caterpillar engine (turbocharged six-cylinder, 365-hp) with York's high- efficiency centrifugal compressor. The full-load coefficient of performance (COP) of the YB chiller is 1.8 at Air-conditioning and Refrigeration Institute (ARI) design conditions and based on the fuel's higher heating value (HHV). When heat is recovered from the chiller's engine and put to use, the system COP (HHV) increases to 2.2, generating additional cost savings. To shrink the chiller's footprint, York packaged all of the engine/compressor components in a steel driveline base and mounted it on the evaporator/condenser tube sheets using neoprene vibration isolators. The rigid driveline maintains the integrity of the system, minimizes vibration on heat exchanger shells, and allows easy disassembly/reassembly if necessary to fit through narrow, low-overhead passageways during installation.

***Pulse-Combustion Hydronic Boiler.** Fulton Boiler has recently been able to improve the power-density of their pulse-combustion hydronic boiler by a factor of two. However, the sound level of the product was increased by 3dba in the process, an unacceptable result. Under the leadership of GRI's Gas Appliance Technology Center (GATC), a team of experts in sound transmission and abatement was quickly assembled to address the issue and to make recommendations for solution. The team identified 61 concepts for sound reduction. Of these, 24 were selected as 1st effort candidates. Within two more weeks, Fulton had selected and tested six of these and found them to be very effective in sound reduction without compromising product design. The result: a 10dba drop in sound level, well below the initial target. Fulton introduced the new line of boilers the next month at the 1997 ASHRAE show in Philadelphia. The benefits of this new line include high power density (small footprint for the same output), quieter operation, and a significant cost reduction.

TRANSPORTATION

FuelMaker-Quantum Vehicle Refueling Appliance Line. A well-established manufacturer of vehicle refueling appliances, FuelMaker Corporation produces a variety of compressors including the low-cost FM4 unit, ideal for time-filling of small and growing fleets. GRI, along with Natural Resources Canada and Gas Technology Canada, supported efforts to make this unit even more economical and useful to a greater variety of fleets. The resulting "Quantum" product line includes three single-compressor and two multi-compressor models, featuring increased gas flow rate, longer service intervals, and elevated discharge pressures. Improving the flow rate from 1.9 scfm to up to 10 scfm for the multi-compressor model reduces the number of refueling appliances needed per fleet. In addition, the two units capable of pressures of 3600 psi extend the driving range of some NGVs. Together with the longer service interval, enhancements in the FuelMaker product line result in a 38% operating cost improvement. The FuelMaker is the only compression system certified by the International Approval Services (IAS).

AccuFill Dispenser Fill Algorithm. During fast-filling of vehicle CNG tanks, the gas temperature inside the cylinder can rise rapidly to 150-160°F. Soon after the dispenser stops filling, the gas inside cools to ambient temperature, and the internal pressure drops, resulting in the underfilling of the tank by up to 20%. This temperature-rise phenomenon was identified by the Institute of Gas Technology, in a GRI-sponsored research, as the worst culprit in the underfilling of NGV tanks. Some dispensers currently attempt to offset these factors during slow time-filling using ambient-temperature compensation devices, but they cannot give a complete fill in fast-fill applications. The new control software, now being licensed to dispenser manufacturers, provides a complete, safe fill under many conditions within 4% of maximum capacity. Walking the line between under filling and over filling will translate to an increased driving range of nearly 10-20% for fast-filled CNG vehicles.

NGV-1 Receptacle/Nozzle Standard Design. In the infancy of the natural gas vehicle market, several refueling accessory manufacturers produced varied and incompatible nozzles and vehicle fueling receptacles. Fleet and refueling station managers were forced to chose a nozzle configuration and then purchase expensive attachments to adapt to other vehicles or stations. In 1994, ANSI, A.G.A. and CGA published standards developed by a GRI program that addressed the design and testing of compressed gas fueling station dispenser nozzles and vehicle receptacles. Entitled NGV-1 "Compressed Natural Gas Vehicle Fueling Connection Devices," the standard ensures interchangeability between products made by different manufacturers. Now almost universally adopted in the NGV market, the NGV-1 nozzle standard has reduced refueling connector costs by up to 50%. Fleet and station managers can more efficiently and safely service the growing population of natural gas vehicles.

POWER GENERATION

***Allison LE IV Dry, Low-Emissions (DLE) Combustor.** In partnership with GRI, Allison Engine Company has developed a dry, low emission combustor-called the LE IV-for its 501K series of 4-MW gas turbines. At a lower cost than selective catalytic reduction (SCR), and without the added maintenance requirements and increased CO emissions of water-injection, the LE combustor reduces NO_x emissions to less than 25 ppm. Both gas pipeline operators and industrial power generators can meet emissions requirements without reducing turbine operation or incurring excessive expenses and constraints associated with other emission control techniques.

***General Electric LM 1600.** In conjunction with GRI, General Electric has developed a dry, low emission annular combustion system for the 13.75-MW LM 1600 aeroderivative gas turbine. The new DLE system dramatically improves the economics of the new installations, as-well-as offering a low cost compliance option for environmental regulations. In full engine test at GE, emissions goals of 25 ppm NO_x, 25 ppm CO, and 20 ppm UHC were met or exceeded.

GAS OPERATIONS

***Orifice Meter Information.** Data developed and collected through GRI-funded projects at the National Institute of Standards and Technology (NIST) and Southwest Research Institute (SwRI) have been used by several gas industry organizations to calculate biases in orifice meter discharge coefficient measurements. These corrections have been used to increase the accuracy of orifice meter measurement and in studies to determine unaccounted-for gas by gas utilities. SwRI also has conducted research to investigate the benefit and feasibility of fitting flow conditioning devices, to assure proper flow conditions upstream of the orifice plate, into new and existing metering installations built to conform with American Gas Association Report No. 3. In an orifice meter installation, the purpose of the flow conditioner is to remove flow disturbances (such as swirl and velocity profile asymmetry) that may arise from common types of pipe fittings, such as elbows, tees and valves upstream of the meter run. The flow conditioner is placed in the meter tube between the disturbing pipe fitting and the orifice meter. The purpose of the flow conditioner device is to remove flow disturbances so values of the orifice discharge coefficients, C_d, are indiscernible from baseline values. Baseline orifice C_d data taken at the Metering Research Facility (MRF), flowing nitrogen, agree well with comparable high accuracy baseline data from other laboratories. The results of the SwRI research effort establish the flow measurement credentials of the MRF Low Pressure Loop. With the completion of the commissioning of the MRF High Pressure Loop, the orifice meter research was expanded to cover larger meter sizes (10") and higher flow/pressure conditions. Also, research was conducted to evaluate various orifice meter configurations without a flow conditioner. This research is being guided by an API working group for revision of the A.G.A./API/ANSI/GPA orifice meter standard (Chapter 14.3, Part 2 - Installation Requirements). The research will support necessary installation specification revisions for use with and without flow straighteners (tube-bundle) and the use of new, improved flow conditioning devices.

Pipeline Current Mapper. GRI and its industry partners have developed a new system that can significantly cut the cost of determining the effectiveness of cathodic protection systems for steel piping systems used to transport natural gas. The Pipeline Current Mapper (PCM) system—manufactured by Radiodetection Corporation—can be used to detect coating defects and points where underground metallic structures come in contact with the pipe. Use of the PCM system by two companies provided an estimated 50% increase in productivity over conventional methods. The payback period was less than six months due to savings in labor, excavations, and a substantial reduction in the number of "electrical test stations" installed to provide a metallic connection to the pipeline.

RENU Service Renewal Technology. GRI and NICOR Technologies Inc. (NTI) have adapted a British technology for U.S. use—named RENU™—that provides an innovative trenchless, time and money-saving technology for renewing gas service lines. Because of the significant potential benefits, GRI funded with NTI both the transfer and the adaptation of the technology. NTI has a license to introduce the product in the United States and Canada. In the time it usually takes a crew (three or four men) to replace one service line using traditional methods of trenching or digging, two crew members can replace three or four lines using the RENU method. This means increased productivity and reduced labor costs for utility companies and contractors. A further advantage is that the equipment and tools for RENU fit easily into a small van, reducing the need for larger, more expensive utility trucks. The technology significantly reduces or eliminates landscaping and paving restoration costs and inconveniences associated with traditional repair and replacement methods. With RENU, standard polyethylene pipe is used for replacement and the method can be used in a variety of weather conditions. Initial installations conducted by Nicor Gas resulted in savings of more than 20 percent over conventional methods.

Pneumatic Tool Diagnostic System (Tool Tester). The Pneumatic Tool Diagnostic System (PTDS) provides a new means to quickly and accurately assess the performance of air-powered tools, such as pavement breakers, rock drills, tampers, and air compressors. Delivered blow energy, blow rate, air pressure, air flow, and rotational speeds are measured and stored in a computer database. The database tracks all tools by inventory number and stores each tool's performance test results and maintenance cost history. The test results allow the operator to quickly pinpoint the area of sub-par performance and then verify that proper operation has been restored after repair. Many utilities use pneumatic tools for hundreds of thousands of man-hours annually and may have inventories of several hundred to several thousand such tools. Field tests with three large U.S. gas utilities of the PTDS proved the system to be reliable and accurate. In addition, studies have shown that tool inefficiencies can cost tens of thousands of man-hours annually. Periodic testing of tools in inventory with the PTDS greatly reduces these losses.

Horizontal Directional Drilling Guidelines. Directional drilling is a no-dig (trenchless) technology, increasingly used by gas utilities to install polyethylene pipes. It involves drilling a pilot hole from the entrance pit to the exit pit to define the installation profile, and pulling the pipeline from the exit pit to the entrance pit as the bore is enlarged through a back-reaming process. Some of the benefits are the ability to install pipelines in tight spaces, the cost-effectiveness of drilling compared to open trenching, the reduction in inconvenience to customers and neighborhoods, and the ability to install pipelines in environmentally sensitive areas. GRI developed guidelines for directional drilling from interviews with gas utilities that use in-house drilling crews, pipeline contractors, and construction companies that perform drilling operations. Additionally, the guidelines include the results of analyses performed on such issues as maximum pull length for a given size pipe. The guidelines are the best practices that should benefit gas utilities by enabling them to develop company-specific internal standards, specifications for contracting for services, and training and quality control procedures.

Hydrostatic Test Water Discharge. Federal (DOT) and state laws require natural gas pipeline companies to maintain the integrity of their pipelines to protect the public from accidents involving potential failure of the pipelines. Hydrostatic testing is the method of choice for verifying pipeline integrity. Little information on the characterization, management, and permitting of hydrostatic test water discharges has been available until recently. Sampling protocols, characterization requirements, permitting procedures, and discharge criteria vary substantially among states. Because of this, the gas industry faces a formidable challenge in developing technically feasible and cost effective approaches to managing hydrostatic test water discharges. In response to these issues and the possibility of more stringent regulatory requirements relating to the discharge of pipeline waters, GRI sponsored an effort to develop industry-specific information on test water discharges. The results of this research effort were documented in a five volume set of GRI reports published in 1992. The most recent GRI-sponsored effort consists of two complementary research programs. The objectives of the first research program were to determine the number of hydrostatic tests for new and used natural gas pipelines, determine the volume of water discharged, determine the management practices used for the discharged test water, assess federal and state regulations pertaining to hydrostatic testing, and to determine research issues. The objectives of the second research program were to develop representative hydrostatic test water characterization data for benzene, BTEX, oil and grease and total solids (TSS) under FIFO (first in, first out) discharge conditions and FILO (first in, last out) discharge conditions, and determine the effectiveness of new and normal industry control devices and water management procedures. A cost effectiveness study showed that pigging was the most effective means of reducing test water contamination, that filter covered hay bales reduced both oil & grease effectively when the pipeline was not pigged, and that air stripping was not cost effective.

PCB Contaminated Pipeline Abandonment Protocol. Fluids containing polychlorinated biphenyls (PCBs) were used as lubricants in natural gas transmission and air compressor systems. Evidence of external contamination from PCB condensate discharged from transmission and distribution systems was discovered about 1987. Use and disposal of materials contaminated with PCBs is governed under the Toxic Substances Control Act (TSCA) and various regulations promulgated by the U.S. Environmental Protection Agency (EPA) in response to TSCA. In 1989, GRI initiated a PCB management research program to investigate innovative PCB management and control technologies. The purpose was to support the gas industry with technical information and management guidance on PCBs, particularly in the areas of statistical sampling, analytical methods, transport, risk assessment, remediation, and removal and control technologies. In the risk assessment phase of the project, a PCB Task Force assessed the potential risks associated with hypothetical releases of PCB-contaminated condensate from natural gas pipelines. The task force evaluated five release scenarios. Results indicated that human health risks associated with PCB releases from pipelines in many cases are within the acceptable range, suggesting that abandonment in place may be a viable disposal alternative. GRI published the information derived from this risk assessment in 1992 and produced a computer program that can be used to quantify the risk of cancer to humans from exposure to PCBs. In 1993, the research shifted in focus to mitigating PCB contamination in gas pipelines. Meeting this objective meant developing an understanding of PCB behavior in pipelines and on pipeline materials and translating this understanding into removal/control engineering guidance.

Low Cost Method for Formaldehyde Measurements. Title III of the 1990 Clean Air Act Amendments (CAAA) requires the U.S. Environmental Protection Agency to develop maximum achievable control technology (MACT) standards to reduce hazardous air pollutant (HAP) emissions from major sources. CAAA defines a major source of HAPs as any source that emits over 10 tons per year (tpy) of a single HAP or 25 tpy of a combination of HAPs. By the year 2000, EPA must issue MACT standards for combustion sources. The combustion source categories covered include stationary internal combustion engines, boilers, process heaters, and turbines. In addition to control requirements, the standards will stipulate monitoring requirements for determining compliance. Radian Corporation, a contractor for GRI, mapped emissions over the full operating range of clean-burn and lean-burn engines, and investigated alternative formaldehyde emission estimation approaches. With test data indicating that formaldehyde emissions vary with operating conditions and engine model, the program focused on identifying engine parameter-based models or low-cost measurement techniques that accurately estimate specific engine-specific formaldehyde emissions at the lowest possible cost. The project provides data and tools needed to develop an inexpensive, reliable method for estimating formaldehyde emissions, determines major source applicability, identifies and develops appropriate formaldehyde emissions control options, including operational modifications, design modifications, and add-on controls, and develops a low cost, reliable EM system to comply with the MACT requirements.

Contained Recovery of Oily Waste Technology Evaluation (CROW™) Technology for Water Cleanup. From the early 1800s to about 1960, manufactured gas plants converted coal or oil to a gaseous fuel, sometimes known as "town gas." The gas was used to light and heat homes, businesses, and factories throughout the United States, although most MGPs operated in cities and towns in the Midwest and East. Many abandoned or demolished MGP sites remain contaminated with wastes and residues associated either with the gas-producing and purifying processes used at these sites or with demolition activities. The Contained Recovery of Oily Waste (CROW™) process was developed and tested with funding from GRI and the EPA SITE program. The CROW process pumps hot water or steam into subsurface oily waste accumulations to make them less viscous and more buoyant and therefore more easily pumped to the surface.

CBT (Chemical-Biological Treatment) Cleanup Technology. Manufactured gas plant (MGP) operations, which generally ceased in the United States by about 1960, resulted in the release of various residuals and by-products to surrounding soils, sediments, and water. Of greatest concern are residual chemicals such as polynuclear aromatic hydrocarbons (PAHs), volatile aromatics, phenolics, inorganic chemicals, and trace metals. Some higher molecular weight PAHs are believed to be carcinogenic and PAH-contaminated soils are pervasive at many former MGP sites. Of the currently favored site remediation strategies, biological treatment appears to offer the best combination of relatively low cost and cleanup effectiveness. But in soils dominated by 4-6 ring PAHs, conventional biotreatment used alone is limited in its capacity to remove organic pollutants. Through a combination of two complementary remedial techniques - chemical oxidation and biological treatment - this limitation may be overcome. GRI, the Institute of Gas Technology's Sustaining Membership Program, U.S. EPA, and several gas companies have sponsored a research program to develop and evaluate an integrated chemical-biological treatment process capable of enhancing the rate and the extent of PAH degradation. The ultimate goal is a treatment technology that serves as a cost-effective alternative to landfilling, thermal treatment or incineration, and other technologies. The chemical-biological treatment is referred to as the MGP-REM process. Following pretreatment, microorganisms present in the PAH-contaminated soil biologically degrade the organic contaminants to carbon dioxide and water. The MGP-REM development and evaluation program consists of three phases: Solid-phase (landfarming) application of MGP-REM; Slurry-phase application of MGP-REM; and In Situ application of MGP-REM.

Gas Plant Emissions/Efficiency Report. This report is a result of a field evaluation of air emissions from combustion equipment at natural gas processing plants. The primary focus of the work was quantification of hazardous air pollutant emissions from natural gas-fired equipment, with other pollutants such as NO_x and CO also measured. Seven internal combustion engines, three incinerators, six heaters, three boilers, and three gas turbines were tested at five facilities. The internal combustion engines were found most likely to pose a potential regulatory concern, due to formaldehyde emissions. Other data indicated that the operating condition of the equipment can affect emissions, with engines tested before and after maintenance exhibiting a decrease in formaldehyde emissions and fuel consumption after maintenance was performed. This two-volume report consists of volume I, which describes the test program and reports the results, and a series of detailed data appendices in volume II. This is the second in a series of two reports presenting the results of a field evaluation of air emissions from combustion equipment at natural gas industry facilities. The first report focused on transmission compressor stations and storage facilities.

Lomic SonicWare™. Lomic, Inc. has developed a software package to assist natural gas metering engineers using ultrasonic metering devices. SonicWare™ provides the user with information to calibrate, monitor, audit and service ultrasonic meters.

Plastic Pipe Reliability (PENT Test). The Polyethylene Notch Test (PENT Test) is a newly developed testing method that facilitates the identification of slow crack growth (SCG) characteristics in polyethylene resin which subsequently identifies the longevity characteristics in polyethylene pipe used in the natural gas distribution industry. The PENT test is used by polyethylene resin manufacturers for broadly identifying important resin failure characteristics in pipe without having to use a more costly hydrostatic test to obtain similar information in PE pipe development. Also, the PENT test can identify SCG rates without having to test the PE pipe itself. The PENT Test can be done using a small sample of resin, eliminating the need to produce a section of pipe for testing.

SUPPLY

Mercury Soil Contamination Program. The natural gas industry used mercury manometers extensively to measure the flow of gas at wellheads, metering sites, and other gas industry operations. Several operational aspects may have caused mercury spillage from the manometers resulting in sites with mercury-contaminated soils. The release of elemental mercury into the natural environment from manometers is a potentially serious problem because of the toxicity of mercury. Research sponsored by GRI and the U.S. Department of Energy and conducted by the Energy & Environmental Research Center (EERC) to address this problem included an industry workshop with published proceedings, the publication of a critical literature review and citation database, a published review of remediation technologies, the development of a risk-based screening model, and a review of sampling and analytical methods for mercury. Additional research included monitoring of six field research sites, a study on containers and preservation techniques for mercury-contaminated samples, testing of thermal desorption, physical separation, chemical leaching and a combination of physical separation/chemical leaching. Activities to date have indicated: 1) contamination is extremely localized and does not migrate to shallow groundwater; 2) specific sampling and analytical techniques must be adopted to provide meaningful data; and 3) various remediation technologies can be used effectively to remove mercury from soil.

Offshore Atlases - Part 2. Radian International LLC, has updated the two-volume Atlas of Northern Gulf of Mexico natural gas and oil reservoirs with the most recent deep water drilling data in the Gulf. Published in late 1997, it includes data on deep water exploration activities from January 1995 to December 1996, a period of significant drilling activity in the Gulf. The atlas provides petroleum geologists with a direct link to vital engineering and geological data, which is a valuable new tool to help guide producers in planning, leasing, acquisitions, and exploring and exploiting the deep water trend in the Gulf. The atlas includes state and federal data that have been compiled into a single source by the Texas Bureau of Economic Geology. The atlas takes 9,947 oil and gas reservoirs from 1,212 fields and classifies them into a geological framework for the region, sorts the sands and fields into plays. The fields represent a total cumulative production of 134.9 trillion cubic feet of natural gas and 12.1 billion barrels of oil. Volume I, published in June, 1997, is a 200-page portfolio that includes descriptions and cross sections of the Miocene and older reservoirs, which account for the majority of plays in the region. Volume II, released in late 1997, covers the younger, Plio-Pleistocene reservoirs, including deeper water plays. The atlas also has a data component on CD-ROM that includes engineering attributes for the 9,947 reservoirs and 91 plays. The atlas is one in a series of six regional atlases on major natural gas plays developed by GRI, DOE and the MMS.

Appalachian Atlas. This is the most comprehensive atlas of natural gas and oil fields in the Appalachian Basin ever published. It is one in a series of six regional atlases on major natural gas plays. The Atlas of Major Appalachian Gas Plays features more than 700 maps, graphs, cross sections, stratigraphic columns, correlation charts, type logs, data tables, and references on more than 30 of the basin's most significant gas plays. It offers a comprehensive analysis of geological, engineering, and production data that will help producers identify exploration and development opportunities in the basin. The atlas is published by West Virginia Geological and Economic Survey.

Underbalanced Drilling Manual. GRI estimates that more than 30 percent of wells drilled in the United States could be safely and cost-effectively drilled using underbalanced technologies, which have been available since the 1970s. Currently, only about 10 percent of wells are drilled in this manner, due chiefly to a lack of knowledge and experience among producers about how to apply these technologies. To fill this knowledge gap, GRI contracted with Terra Tek Inc., to consolidate into one document a significant body of publicly-available knowledge, protocol and experience about underbalanced drilling. GRI's

Underbalanced Drilling Manual is a collation of industrial experience in underbalanced drilling. It is a state-of-the-art manual that provides the basic background knowledge for the evaluation, selection, design and planning of underbalanced drilling operations. The impacts of wider underbalanced drilling application are improved penetration rates (decreased drilling costs) and decreased formation damage. The manual characterizes various techniques and methodologies, including air, nitrogen, natural gas, mist, foam, mudcap drilling, flowdrilling, coiled tubing drilling, snub drilling, and closed systems. The manual is available from the Society of Petroleum Engineers or the International Association of Drilling Contractors.

Freeze/Thaw for Production Water. When natural gas is extracted at the wellhead or withdrawn from a storage reservoir, a substantial volume of water is co-produced with the gas. Produced water constitutes more than 80% of the wastes and residuals generated from the production of natural gas. Consequently, produced water management practices and water disposal costs are issues of growing importance. GRI supports research to identify and develop cost-effective and environmentally acceptable management strategies for produced water. One such treatment technology couples winter season freezing and thawing with summer season solar evaporation. The freeze-thaw/evaporation (FTE^{SM}) process works on the principle that a brine solution with elevated total dissolved solids (TDS) concentrations has a lower freezing point than purified water. The technology provides an opportunity to use natural conditions to purify or dispose of produced water year-round. A typical FTE facility design consists of a produced water holding pond, a freezing pad, and a treated water storage pond or facility. When the ambient temperature drops below 0°C, produced water is sprayed onto the freezing pad, forming an ice pile in the process. The dissolved solids concentrate in a brine, which drains from the pad. When the temperature is higher than 0°C, the ice pile melts and the treated water, which contains significantly lower TDS concentrations, drains from the freezing pad. Automated monitoring and processing through the use of a system of sensors and valves allows for ready identification and sorting of runoff. The brine is disposed of by conventional methods and the treated water is stored for later beneficial use or is discharged. Since 1992, research has been sponsored by Amoco Production Company, the U.S. Department of Energy, and GRI to develop a commercial, natural freeze-thaw/evaporation purification process for produced waters. Since 1995, B.C. Technologies, Ltd. (BCT) and the University of North Dakota Energy and Environmental Research Center (EERC) have been successfully testing an automated produced water treatment and disposal facility that uses the FTE process. The FTE process has a definite economic advantage over conventional evaporation technology in climates with seasonal subfreezing ambient temperatures. Importantly, reduced water treatment/disposal costs can result in increased production from economically marginal gas resources and in the development of new unconventional sources such as coalbed methane.

Glycol Dehydrator Controls/Monitoring. Monitoring glycol dehydrator control devices in the field to verify compliance with emissions limitations could be expensive. To provide a more cost-effective method, GRI established a control device monitoring program to validate the concept that the condenser outlet temperature is the only control device parameter needed for monitoring a still vent condenser. Another objective was to collect the data needed to validate the potential use of computer programs, such as GRI-GLYCalc 3.0, to generate accurate, site-specific condenser curves. GRI contracted Radian International LLC to perform the data collection and field evaluation. Radian collected data during nine tests over a range of condenser configurations and operating temperatures. Several types of condensers, including air-, glycol-, and water-cooled, were tested. Each of the nine tests consisted of six runs. Radian used the field data as inputs for various computer modeling approaches and compared the modeling results with the field measurements. The results of the study show that condenser outlet temperature can be used as a monitoring parameter for a given unit. The data also shows that computer programs such as GRI-GLYCalc 3.0 can be used to develop site specific condenser control device emission efficiency curves for use in conjunction with outlet temperature as a control device monitoring tool. Computer modeling of condenser performance is expected to cost less than direct field measurement of performance.

Coalbed Reservoir Gas-In-Place Analysis Short Courses. Tesseract Corporation and TICORA Geosciences in conjunction with GRI developed an improved analysis protocol for determining the reservoir parameters used for calculating the gas-in-place volume of coalbed reservoirs. GRI's research showed that many commonly used methods for determining critical reservoir parameters such as the gross thickness, average rock density, and average in-situ sorbed gas content have inherent shortcomings which collectively can result in up to 50% or greater underestimation error in the gas-in-place volume. GRI's improved analysis protocol enables the more accurate determination of these three critical reservoir parameters. During 1997, GRI conducted three, 2-day short courses which provided hands-on training to 65 petroleum geologists and reservoir engineers in the use of this improved analysis protocol.

☼ Enhancement to a previous winner.

Appendix B
GRI R&D Results That Have Been Placed in Commercial Use in 1993 Through 1997

RESIDENTIAL

1. York Triathlon™ Natural Gas Heating and Cooling System - 1994
2. Technology Options for Multifamily Housing - 1995
3. Water Heater Powered Desiccant Dehumidifier - 1995
4. Protocol for Water Heater Emissions Measurement - 1995
5. Venting Guidelines for 1996 National Fuel Gas Code - 1995
6. Test Protocols for High-Temperature Plastic Vents - 1995
7. Home Energy Rating System Guidelines - 1995
8. Compact Gas Meter - 1995
9. Gas Load Center - 1995
10. Carrier "Chimney Friendly" Furnace - 1996
11. Empire Gravity Vented Wall Furnace - 1996
12. Modulating Furnace by RHEEM - 1996
13. Utility-to-Customer Communication (Whisper) - 1996
14. Hearth Products Technology Base - 1996
15. Outdoor Gas Water Heater (American Water Heater Co.) - 1997
16. Advanced Gas Fireplace (Lennox) - 1997

COMMERCIAL

17. Pulse Combustion Hydronic Boiler - 1989/91/97
18. Automated Deep-Fat Fryer -1993
19. 340RT Large Engine Chiller - 1994
20. 485RT Large Engine Chiller - 1994
21. Millennium™ Engine-Driven Chillers - 1994/95
22. Gas Combination Oven/Steamer - 1994
23. Standard Test Method for Performance of Steam Cookers - 1994
24. Standard Test Methods for Performance of Range Tops - 1994
25. Batch Booster Water Heater - 1995
26. Restaurant-Sized Steam Combination Oven - 1995
27. GATC Quick Response Activities - 1995
28. 725RT Large Engine Chiller (Tecogen) - 1995
29. Trane Modulating Rooftop Unit - 1996
30. Trane Horizon Absorption Chiller - 1996
31. Low Emissions Package for Engine Chillers - 1996
32. Separation Requirements in ASHRAE Standard 62-89R - 1996
33. Food Service Ventilation Code Data - 1996
34. BinMaker™: The Weather Summary Tool - 1997
35. TecoFROST™ Gas Engine Driven Refrigeration - 1997
36. York Millennium™ GED, Model YB - 1997

INDUSTRIAL

37. Ion-Nitriding GASFIRED™ Vacuum Furnace - 1994
38. Process Application of Composite Radiant Tubes - 1994
39. DONLEE TurboFire® XL Boiler - 1994
40. Heat Treat Furnaces - 1995
41. Low NO_x Air Staging for Glass Melting - 1995
42. Glass Tempering Furnace - 1995
43. Industrial Boiler Gas Cofiring - 1995
44. High Performance Infrared Burners - 1995
45. Steel Products Heating Furnace - 1995
46. ALZETA Pyrocore® Ceramic Fiber Burner for Various Heating Applications - 1985/96
47. Volatile Organic Compound Abatement Technology - 1996
48. CYCLOMAX® Low NO_x Industrial Burner - 1996

POWER GENERATION

49. Conventional Gas Reburn - 1995

TRANSPORTATION

50. Cummins L10-G Series - 1991/95
51. Chrysler Minivan - 1993
52. Advanced Conversion System of Vehicles to CNG - 1993
53. Hercules 3.7-liter NGV Engine - 1994
54. Cummins B5.9G Series - 1994
55. DDC Series 50G - 1994
56. CAP 4.3L Natural Gas Engine - 1994
57. Ford Motor Company's QVM (Qualified Vehicle Modifier) Program - 1994/95
58. Ford Crown Victoria Natural Gas Vehicle - 1995
59. Cummins C8.3G Engine - 1996
60. John Deere 8.1L Engine - 1996
61. DDC Series 30G - 1996
62. Caterpillar Dual-Fuel Truck Engine - 1996
63. MACK E7G Refuse Hauler - 1996
64. Ford Vans and Pickups - 1996
65. GFI/GEM Forklifts - 1996
66. FuelMaker-Quantum Vehicle Refueling Appliance Line - 1997
67. AccuFill Dispenser Fill Algorithm - 1997
68. NGV-1 Receptacle/Nozzle Standard Design - 1997

GAS OPERATIONS

69. Excess Flow Valve Information - 1985/94
70. Polyethylene Pipe Butt-Fused Joint Flaw Detectors - 1987/88/93
71. SoLoNO_x™ Gas Turbine Combustor - 1992/95

72. Electronic Marker System for Locating Buried PE Gas Pipes - 1993
73. Visual Internal Inspection System - 1993
74. Electrostatic Discharger System - 1993
75. Guidelines for Enhanced Electrofusion Joining Qualification and Acceptance Testing of PE Gas Pipes - 1993
76. LNGFIRE2 LNG Pool Fire Program - 1993
77. Compressor Diagnostic Software - 1993
78. GE Dry Low NO_x Combustor - 1993/97
79. ENSYS Rapid Field Test Kit for PCB Soil Contamination - 1993
80. GRI PCB Risk Assessment - 1993
81. GRI Groundwater and Contaminated Soil Environmental, Health and Safety Information System - 1993
82. LIFESPAN PE Program - 1994
83. Single-Line Electronic Flow Measurement (EFM) Device - 1994
84. Low-Cost NO_x Controls for 4-Cycle Ingersoll-Rand Pipeline Engines (Dresser-Rand) - 1994
85. Low-Cost NO_x Controls for 2-Cycle CLARK™ Pipeline Engines (Dresser-Rand) - 1994
86. Low-Cost NO_x Controls for 2-Cycle GMV Series Pipeline Engines (Cooper Industries) - 1994
87. Acoustic Pipe Tracer - 1995
88. Relining of Cast Iron and Steel Pipe - 1995
89. Coiled Plastic Pipe Information - 1995
90. Guidelines for Low-Cost, OSHA-Approved, Shoring Design and Materials - 1995
91. Plastic Pipe Across Bridges - 1995
92. SmartHeat™ Induction Fusion System - 1995
93. Soil Compaction Meter - 1995
94. RAPTOR Well Test Design and Analysis Software - 1995
95. OMNET Surface/Subsurface Modeling Software - 1995
96. Clock Spring® Composite Pipeline Repair Material - 1995
97. ASD CEMcat Continuous Emission Monitoring System - 1995
98. Allison 501-K Low NO_x Combustor - 1995/97
99. Inspection Vehicle for Unpiggable Lines - 1995
100. Methodology to Estimate Methane Emissions from Gas Operations (STAR Program) - 1995
101. Anaerobic Cast Iron Joint Repair Guide - 1996
102. DrillPath Guided Boring Software - 1996
103. Cast-Iron Maintenance and Optimization System (CIMOS) - 1989/1996
104. Assessment of Gas Pipeline Non-Destructive Evaluation (NDE) Technologies - 1996
105. Airborne Pipeline Integrity Monitoring (APIM) Assessment - 1996
106. Pipeline Inspection and Maintenance Optimization System (PIMOS) - 1996
107. Remote and Automatic Controlled Valves Guidelines - 1996
108. Risk Assessment/Risk Management Guidelines - 1996
109. Third-Party Damage Prevention Assessment - 1996
110. Carbon Monoxide Detector Supplemental Standards - 1996
111. Manufactured Gas Plant (MGP) Site Management Guidebooks (4 Volume set) - 1996
112. Cost Model for MGP Site Cleanups - 1996
113. Soil Cofiring in Utility Boilers at MGP Sites - 1996
114. Thermal Desorption for Soil Cleanup at MGP Sites - 1996
115. Orifice Meter Information - 1990/92/97
116. Pipeline Current Mapper - 1997
117. RENU Service Renewal Technology - 1997
118. Pneumatic Tool Diagnostic System (Tool Tester) - 1997
119. Horizontal Directional Drilling Guidelines - 1997

120.Hydrostatic Test Water Discharge - 1997
121.PCB Contaminated Pipeline Abandonment Protocol - 1997
122.Low Cost Method for Formaldehyde Measurements - 1997
123.Contained Recovery of Oily Waste Technology Evaluation (CROW) Technology for Water Cleanup - 1997
124.CBT (Chemical-Biological Treatment) Cleanup Technology - 1997
125.Gas Plant Emissions/Efficiency Report - 1997
126.Lomic SonicWare™ - 1997
127.Plastic Pipe Reliability (PENT Test) - 1997

SUPPLY

128.Atlas of Major Central and Eastern Gulf Coast Gas Reservoirs - 1993
129.Atlas of Major Mid-Continent Gas Reservoirs -1993
130.Atlas of Major Rocky Mountain Gas Reservoirs - 1993
131.Amplitude Variation with Offset - 1993
132.Tekstim® 3523 Coal Seam Surfactant - 1993
133.Gas Content Correlation for the Antrim Shale - 1993
134.Coalbed Methane Produced Water Management Guide - 1993
135.Quantitative Gas Measurement - 1994
136.Wireless Telemetry Tool - 1994
137.Electrical Survey Log Software - 1994
138.Successful Drilling Practices - 1995
139.Eppendorf CS-200 Analyzer for Optimization of Amine Unit Operations - 1995
140.CO_2 Membrane Database - 1995
141.R-BTEX Emissions Control Process - 1995
142.Secondary Gas Recovery, Gulf Coast and Mid-Continent - 1995
143.Produced Water Treatment Calculation Cost Model (ProWCalc) - 1995
144.Fourier Transform Infrared Technique (FTIR) for HAPs Measurements - 1995
145.GRI-HAPCalc Screening Tool - 1995
146.Production Water/Waste Management and Site Remediation Treatment Technology Database, GRI-TTBD - 1995
147.Chemicals Used in Gas Operations Database, GRIChem-USE - 1995
148.Drilling Waste Atlas and Produced Water Atlas - 1995
149.Improved Coal Seam Gas Content Measurement Method (CoreGas Database) - 1995
150.Emerging Resources in the Greater Green River Basin - 1996
151.Scavenger CalcBase Database - 1996
152.Fracturing Fluid Characterization Facility (FFCF) - 1996
153.A Guide to Determining Coalbed Gas Content - 1996
154.Coalbed Methane Engineering Manual - 1996
155.Gas Composition Database - 1996
156.Title V Permitting Guidance - 1996
157.Environmental Technology Information Center (ETIC) - 1996
158.Granular Activated Carbon-Fluidized Bed Reactor (GAC-FBR) - 1996
159.Mercury Soil Contamination Program - 1997
160.Offshore Atlases - Part 2 - 1997
161.Appalachian Atlas - 1997
162.Underbalanced Drilling Manual - 1997

163.Freeze/Thaw for Production Water - 1997
164.Glycol Dehydrator Controls/Monitoring - 1997
165.Coalbed Reservoir Gas-In-Place Analysis Short Courses - 1997

** This product is no longer available for sale or it has been superseded by a new model incorporating the GRI technology.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 53
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 49, Alternative Receipt Point Service. Provide cost support for the proposed distribution charge of $.10 per Mcf.

Response:

Western's rationale for establishing the rate for the Alternate Receipt Point Service, Rate T-5, recognized several factors. First, as discussed in detail in the testimony, Volume 2 of 10, Tab 11, at pages 31-33, availability of this service is subject to several limitations. T-5 Service, if available to a specific customer, presents a new, "added-cost" option for the customer - in other words, the customer may choose to utilize an alternate receipt point under the conditions of the T-5 tariff, or avoid the additional $0.10/Mcf fee by continuing to utilize their traditional upstream supply interconnect.

Administrative tasks for Western associated with providing this service include added transportation nomination and balancing complexities, additional system monitoring requirements at the point of receipt into Western's system, and accounting / contractual issues related to T-5 transactions.

Although Western did not perform cost or valuation analyses, the level of $0.10 per Mcf was proposed in recognition of these additional complexities faced by Western in providing and managing this new service, as well as the clear capability of the customer to assess this cost in their election to utilize this service.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 54 a-d
Witness: Smith

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 51, Special Charges.

a. Even though rate schedules G-1, G-2, LVS-1, LVS-2, T-3, and T-4 all include sections headed "Late Payment Charge," Sheet No. 51 and the Testimony of Gary L. Smith, indicate the proposed Late Payment Charge of 5 percent will be applied only to Rate G-1 sales service. Explain the reasoning for applying the 5 percent charge to only one rate schedule.

b. What other local gas distribution companies is Western aware of that have a late payment charge which is applicable to only one of several rate schedules?

c. What is the purpose of the Late Payment Charge section in the tariffs, other than Rate G-1, identified in part (a) above?

d. Provide the amount of annual revenue that Western expects the Late Payment Charge to generate. Include supporting calculations and sufficient narrative explanation to explain the calculations.

Response:

a. Western's experience is that the residential class of customers served under Rate G-1 is the class of customers most likely not to pay on time. Since this is also the largest class of customers served, some 84%, Western believes that the greatest benefit can be derived by applying a late payment charge to that class of customers. Since one of the rate design goals of this case is Rate Equity, it is logical to first seek new sources of revenue from the class most likely responsible for the credit and collections costs incurred by the Company and most in need of an incentive to pay on time.

b. Although Western determined that several other LDC's in Kentucky do apply Late Payment Charges, we did not conduct a survey of those LDC's to assess their application of late payment penalties among different rate classes.

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DR Item 54 a-d
Witness: Smith

c. This language has been in Western's tariffs for a long time. The language was designed to outline the conditions under which a late payment penalty would apply if in effect for a given rate class. Western prefers to leave this language in the tariff at this time, even though it is not proposing to apply a late payment penalty to these rate classes.

d. Please refer to the response to Data Request 57 (d), which provides a workpaper that details the components of Other Revenue for the Test Year, applying present and proposed rates. Included on that attachment is Western's forecast of $308,304.
Western estimated the dollar value to which the Late Payment Fee would be applied in the following manner.

Total Annual Residential Revenue, present margins:	$68,349,045
Annual Rate Increase Requested:	9,221,264
Total Annual Residential Revenue, proposed margins:	77,570,309
Approximate Residential Revenues, 11months:	61,660,820
Assume Late Payment applied to 10% of Total Revenues	6,166,082
5% Late Payment Charge	$308,304

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 55
Witness: Smith & Marks

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 30a, Demand-Side Management Cost Recovery Mechanism, and the Testimony of Gary L. Smith and Michael Marks on the same subject.

a. Explain why the WKG CARES program is proposed for another three years, as opposed to one or two years, or on a permanent basis.
b. What consideration, if any, was given to implementing the program on a permanent basis?
c. Are the non-permanent nature of the proposed three-year program and the proposal to recover costs for the three-year pilot program the only reasons for proposing a surcharge mechanism rather than including the prospective costs for recovery through base rates? If there are other reasons for using a surcharge mechanism, explain them in detail.
d. The tariff itself does not specifically mention the annual filing with the Commission discussed in the Testimony of Michael Marks. Was this an oversight or intentional? Provide any reasons why Western would be opposed to including a statement in the tariff identifying and describing the annual filings proposed by Mr. Marks.

Response:

a. It seems appropriate that such a program should be periodically reviewed. Western's proposal to extend the program through 2002, anticipates that such an evaluation would be appropriate approximately every three years. Setting the program's termination date in concert with this interval ensures that any extension, modification or termination of the program occurs with the benefit of such a review. On page 17 of his testimony, Mr. Marks recommends a review of the program should the program be extended beyond 2002.
b. None, for the reasons stated in the response to a. above.
c. The surcharge mechanism is certainly not inconsistent with the non-permanent nature of the proposed program and recovery of pilot program costs. However, the primary purpose of the proposed surcharge mechanism is to ensure that the costs of this program are recovered from the appropriate class of customers, consistent with KRS 278.285, and not from Western's shareholders. Mr. Smith's testimony points out that the "Revenue requirements associated with the DSM program are incremental to the Company's deficiency in this case; therefore, the DSM surcharge is excluded from the summary of proposed revenues" (page 33). Including these costs in the calculation of base rates would result in shareholders paying for a portion

or all of the program if Western's earnings were to fall below its allowed return.

d. The tariff specifically mentions the annual filing referenced in Mr. Marks' testimony. Please see the bottom paragraph of proposed Tariff Sheet 30B.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 56 a
Witness: Ives

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 67, Rules and Regulations, Part (l), Premises charge and the Testimony of Daniel Ives.

a) The proposed Premises Charge is only for the residential customer class and Mr. Ives discusses this on page 11 of his testimony. Even though 84 percent of customer growth is in the residential class, explain why Western would choose not to address the same problem of incremental versus embedded costs for the remaining one-sixth of its customer growth occurring in other customer classes.

Response:

a) As discussed in Section IV of Mr. Ives' testimony, the Residential class of customers has not earned the allowed rate of return when examined in class cost of service studies and when examined in studies by other consultants. Mr. Petersen's class cost of service study in this case indicates that the Firm Industrial and Interruptible and Carriage classes are each earning above the system average rate of return and the rate of return sought by the company in this case. Mr. Smith testifies that by-pass options in the highly competitive Large Interruptible and Carriage market preclude the company from increasing margins to that sector. Finally, with respect to the Firm Commercial class, a Premises Charge might be appropriate on an earned return basis, as the class earns less than a system average rate of return and less than the return requested by the company in this case. However, as the preponderance (84%) of customer growth is in the Residential class, it was deemed that the problem is essentially caused by Residential growth.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 56 b
Witness: Ives

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 67, Rules and Regulations, Part (l), Premises charge and the Testimony of Daniel Ives.

b) On page 10 of his testimony Mr. Ives discusses the proposed fifteen-year recovery period for the Premises Charge. Explain why a shorter life, based on the Internal Revenue Service's MACRS system, is appropriate for per books accounting by a regulated entity.

Response:

b) Mr. Ives does not propose use of the IRS' MACRS depreciation system for per books accounting by a regulated entity. Mr. Ives simply references the IRS' MACRS depreciation system as one that recognizes that economic lives may be shorter than physical lives. Mr. Ives uses this analogy as part of his thought process in determining what life might be appropriate for recovery of the Premises Charge.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 56 c
Witness: Ives

Data Request:

Refer to Volume 1 of 10 of the Application, Tab 6, Proposed Tariffs, at Sheet No. 67, Rules and Regulations, Part (l), Premises charge and the Testimony of Daniel Ives.

c) Provide support for Mr. Ives statement that "a fifteen-year recovery period is consistent with what is being used elsewhere in the industry."

Response:

c) Refer to Mr. Ives' testimony on Page 17, line 25, through Page 18, line 2. At least two other companies in the industry, Questar and Minnegasco, utilize 15-year recovery periods.

See also attached documents:

1) Questar Gas Tariff Page 60
2) Minnegasco Tariff Pages 10,10.a, 10.b, 10.c, 10.c-1

tenants. This exemption does not apply to RPO accounts initiated at the time of execution of the referenced agreement.

NEW-PREMISES FEE

Temporary charge assessed to the occupants of a residential premises, excluding multi-family dwellings and mobile homes, with a new premises number. The charge, as specified below is to be collected for twelve payments. Tax at the applicable state and local rates will be charged on the New-Premises Fee.

EXTENSION AREA CHARGE AND EXPIRATION DATE

The following table describes the areas in which the Extension Area Charge applies, the amount of the charge for residential and commercial customers and the date on which the charge is due to expire for each new extension area.

Area Definition	EAC	Expiration Date
Ogden Valley - An area which includes the Town of Huntsville, the communities of Eden and Liberty and unincorporated areas in Eastern Weber County and Northwestern Morgan County adjacent to the gas line to this area.	Regular Tariff Rates Plus: Residential Customers: $27.50/mo. Commercial Customers: $27.50/mo. plus $2.5191/Dth for usage over 45 Dth/mo.	November 1, 2011
New Harmony - New Harmony and the area adjacent to the tap line serving New Harmony.	Regular Tariff Rates Plus: Residential Customers: $25.14/mo. Commercial Customers: $25.14/mo. plus $2.6235/Dth for usage over 45 Dth/mo.	November 1, 2007
Panguitch - Panguitch and the area adjacent to the tap line serving Panguitch.	Regular Tariff Rates Plus: Residential Customers: $30.00/mo. Commercial Customers: $30.00/mo. plus $2.7481/Dth for usage over 45 Dth/mo.	November 1, 2013
Oak City - Oak City and the area adjacent to the tap line serving Oak City.	Regular Tariff Rates Plus: Residential Customers: $20.00/mo. Commercial Customers: $20.00/mo. plus $2.0870/Dth for usage over 45 Dth/mo.	November 1, 2013
Joseph & Sevier - Joseph and Sevier and the areas adjacent to the tap lines serving Joseph and Sevier.	Regular Tariff Rates Plus: Residential Customers: $20.00/mo. Commercial Customers: $20.00/mo. plus $2.0870/Dth for usage over 45 Dth/mo.	November 1, 2013

New Area Surcharge Rider

Availability: Service under this rate schedule is available only to geographical areas that have not previously been served by the Company. This rate schedule will enable natural gas service to be extended to areas where the cost would otherwise have been prohibitive under the Company's present rate and service extension policy. Nothing in this rate schedule shall obligate the Company to extend natural gas service to any area.

Applicability and Character of Service: All customers on this rate shall receive service according to the terms and conditions of one of the Company's gas tariff services.

Rate: As authorized by the MPUC, the total billing rate for any customer class will be the applicable cost of gas, approved rate (monthly basic plus delivery charge) for that customer class plus a fixed monthly new area surcharge. All customers in the same rate class will be billed the same surcharge. The New Area surcharge will be treated as a Contribution-in-Aid-of-Construction for accounting and ratemaking purposes.

Method: A standard model will be used that is designated to calculate the total revenue requirement for each year of the average service life of the plant installed. The model will compare the total revenue requirements for each year with the retail revenues generated from customers served (actual and/or expected) by the project to determine if a revenue deficiency or revenue excess exists.

The Net Present Value (NPV) of the yearly revenue deficiencies or excesses will be calculated using a discount rate equal to the overall rate of return authorized in the most recent general rate proceeding. Projected customer CIAC surcharge revenues are then introduced into the model and the resultant NPV calculation is made to decide if the project is self supporting. A total NPV of approximately zero ($0) will show a project is self supporting.

The model will be run each year after the initial construction phase of a project wherein actual amounts for certain variables will be substituted for projected values to track recovery of expansion costs and the potential to end the customer surcharge before the full term. The variables which will be updated in the model each year will be:

The actual capital costs and projected remaining capital costs for the project.

Number of customers used to calculate the surcharge revenue and the retail margin revenue;

The actual surcharge and retail revenue received to date and the projected surcharge and retail revenue for the remaining term of the surcharge.

Date Filed: November 18, 1994 Effective Date: August 30, 1995
Docket No.: G-008/M-94-1075
Issued By: Phillip R. Hammond, Vice President, Supply Management and Regulatory Services

Minnegasco
Section V
First Revised Page 10.a
Replacing Original Page 10.a

New Area Service Rider (Continued)

Term: The term of service under this rate schedule shall vary from area to area depending on the service extension project. However, under no circumstances shall the surcharge applicable to any project remain in effect for a term to exceed fifteen (15) years. The Company assumes the risk for underrecovery of expansion costs, if any, which may remain at the end of the maximum surcharge term.

Expiration: The surcharge for all customers in an area subject to the New Area Service Rider shall end on the date specified for the project tariff, on the date the approved revenue deficiency is retired, or at the end of fifteen (15) years, whichever occurs first.

Revenue Requirements Model

Definitions: All terms describe contents and general operation of the Revenue Requirements Model used to determine a New Area Surcharge Rider for a project.

Column/Description

1. Time Period: Twelve (12) month calendar interval which is one year of the project life. The year in which the project is constructed is designated as year 0.

2. Year.

3. Gross Plant Investment: Cumulative plant in service at the end of the year reduced by the net present value of surcharge revenues in year 0. Plant in service shall be all capitalized costs incurred to provide or capable of providing utility service to the consuming public. Capitalized costs will include items such as pipeline interconnects, pressure regulating facilities, measurement and instrumentation, lateral delivery lines, distribution mains, mapping, customer service lines, meters and regulators.

4. Accumulated Depreciation Reserve: Book depreciation for the current year plus all previous years.

5. Net Plant In Service: The difference between Gross Plant Investment (Column 3) and Accumulated Depreciation Reserve (Column 4).

6. Average Net Plant: Average of Column 5.

7. Average Accumulated Deferred Income Taxes: The average of the beginning and the end of the year accumulated deferred income tax. Accumulated deferred income tax (ADIT) consists of two components: accumulated deferred income taxes on depreciation and accumulated deferred income taxes on contribution in aid of construction. At the end of the service life of the plant installed the balance of ADIT will be zero.

8. Average Rate Base: Total of Average Net Plant (Column 6) plus Average Accumulated Deferred Income Taxes (Column 7).

Date Filed: November 18, 1994 Effective Date: August 30, 1995
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Issued By: Phillip R. Hammond, Vice President, Supply Management and Regulatory Services

New Area Service Rider (Continued)

9. Allowed Return: Derived from Minnegasco's most recent general rate proceeding:

Equity Ratio	x	Return on Equity	x	(1+Tax Rate)	=	Weighted Cost
Long Term Debt Ratio	x	Debt Cost			=	Weighted Cost
Short Term Debt Ratio	x	Debt Cost			=	Weighted Cost
						Allowed Rate of Return

The Allowed Rate of Return multiplied by the Average Rate Base (Column 8) equals the Allowed Return.

10. Book Depreciation: The straight line cost recovery of the life of the assets for Gross Plant Investment defined in Column (3). The depreciation factor used is based on a weighted average of depreciation rates used in Minnegasco's most recent general rate proceeding.

11. O & M Expense: In any year shall be based on average incremental cost per customer. The cost per customer will include provisions for incremental distribution and customer accounting expenses.

    The calculation is average customers multiplied by incremental cost per customer.

12. Property Tax: In any year shall be a factor of the gross plant investment (after contribution-in-aid-of-construction). The factor is based on historical experiences of actual taxes paid as a percentage of gross plant.

13. Total Revenue Requirement: Total of Allowed Return (Column 9), Book Depreciation (Column 10), O & M Expenses (Column 11), and Property Tax (Column 12).

14. Retail Revenue: This amount represents the retail revenue generated by multiplying the various retail billing rates (basic charge and delivery charge) approved in the Company's most recent general rate case proceeding by the expected average annual number of customers connected to the project each year.

15: Revenue Excess or (Deficiency): Revenue excess or deficiency is the difference between the Total Revenue Requirement (Column 13) and the amount of Retail Revenue (Column 14). Excess occurs when the Total Revenue Requirement in a given year is less than the total Retail Revenue generated. Deficiency occurs when the Total Revenue Requirement in a given year is more than the total Retail Revenue generated.

New Area Service Rider (Continued)

16. **Present Value of Cash Flows:** The cash flows that produce either revenue excesses or deficiencies (Column 15) are discounted to a present value using a discount rate equal to the overall rate of return established in the most recent general rate proceeding.

    If the sum of the present value calculations over the life of the project is zero, or as close to zero as possible, the model demonstrates that the project is "self supporting". That is, the customer CIAC surcharge is the proper amount of customer contributed capital necessary to support the project at the projected (or actual) level of retail revenues.

Surcharge Rider Rates

A surcharge as designated will be included in the monthly bills of the following Minnesota geographical areas:

NORTHERN NATURAL

Areas	Residential Customers	Commercial & Industrial Customers	Small & Large Interruptible Customers	Expiration Date
Carlos Project	$4.75	A $ 8.55 B $14.25 C $33.25	LGS $ 95.00 SDFA $ 47.50 SDFB $ 71.25 LDF $190.00	Sept. 30, 2012

VIKING

Areas	Residential Customers	Commercial & Industrial Customers	Small & Large Interruptible Customers	Expiration Date

Date Filed: May 30, 1997 Effective Date: August 13, 1997
Docket No.: G-008/M-97-807
Issued By: Phillip R. Hammond, Vice President, Supply Management and Regulatory Services

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 57 a through c
Witness: David H. Doggette

Data Request:

Refer to Volume 2 of 10 of the Application, the Testimony of David H. Doggette, pages 12-14, and Exhibit DHD-2.

a. Some of the service charge studies discussed by Mr. Doggette and included in Exhibit DHD-2 covered Western's fiscal year 1998. Identify any studies, other than the April 1999 survey of banks, that cover a period other than fiscal year 1998.

Response:

In the Special Service Charge Analysis the average time to complete work orders covers the calendar year March 1998 through February 1999.

b. Does the summary analysis on Exhibit DHD-2, page 1 of 8, at Column 3, represent the actual number of orders charged for fiscal year 1998, or does it represent the actual number of orders for any period? Explain what Column 3 represents.

Response:

Column 3 on Exhibit DHD-2, page 1 of 8, represents adjustments to DHD-2, page 7 of 8, for anticipated changes in growth and to reflect the restructuring of special charges.

c. Explain why Exhibit DHD-2, page 1 of 8, does not include all the special charges included in Western's proposed tariffs at Sheet No. 51.

Response:

Exhibit DHD-2, page 1 of 8, only includes those special charges related to customer service activity that Western is seeking to change.

Western Kentucky Gas Company
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KPSC Data Request Dated July 16, 1999
DR Item 57 (d)
Witness: Smith

<u>Data Request:</u>

Refer to Volume 2 of 10 of the Application, the Testimony of David H. Doggette, pages 12-14, and Exhibit DHD-2.

d. What impact, if any, do the proposed revenues in Exhibit DHD-2, page 1 of 8, Column 15, or the increase in revenues in Column 16 have on the increase in Other Revenues derived from comparing Exhibits GLS-7 and GLS-1 of the Testimony of Gary L. Smith?

<u>Response:</u>

d. The workpapers utilized to calculate Other Revenues for Exhibits GLS-1 and GLS-7, are attached as Schedule PSC DR NO. 1, DR 57(d), Sheets 1 and 2 respectively. As noted on these workpapers, the charge for each service activity was set in accordance with the cost analysis of Mr. Doggette.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 57 (d)
Witness: Smith

Line No.		(a)	(b)	(c)	(d)	(e)	(f)
		Actual Orders Charged	Pro-forma Orders Charged Normal Hrs	Pro-forma Orders Charged After Hrs	Present Rates Normal Hrs	Present Rates After Hrs	TOTAL REVENUE
1	**SERVICE CHARGES, CURRENT RATES**						
2	Meter Set	2,594	2,555	5	$ 28.00	$ 28.00	$ 71,680
3	New Sct Transfer	180	149	1	28.00	28.00	$ 4,200
4	Turn On New Customer	13,286	13,251	24	18.00	18.00	$ 238,950
5	Turn On Transfer	1,423	1,392	8	18.00	18.00	$ 25,200
6	Turn On Read Only	20,955	20,930	4	10.00	10.00	$ 209,340
7	Transfer Read Only	2,914	2,900	0	10.00	10.00	$ 29,000
8	Turn On from Off Temporarily	58	50	0	25.00	25.00	$ 1,250
9	Off Temperarily At Customer Request	158	146	4	-	-	$ -
10	Turn On from Non-pay	2,543	2,480	20	-	-	$ -
11	Off Temperarily - Delinquent Bill	6,021	6,000	0	-	-	$ -
12	Field Collection Charge	8,191	8,200	0	5.00	5.00	$ 41,000
13	Special Meter Reading Charge	N/A	N/A	N/A	-	-	$ -
14	Returned Check Charge	3,030	3,000	N.A.	15.00	N.A.	$ 45,000
15	Class 1 EFM Equipment Charge	607	622	N.A.	105.00	N.A.	$ 65,310
16	Class 2 EFM Equipment Charge	67	67	N.A.	210.00	N.A.	$ 14,070
17	Premises Charge - Requiring Main Extension				-	-	$ -
18	Premises Charge - Not Requiring Main Extension				-	-	$ -
19	Late Payment Charge				-	N.A.	$ -
20	TOTAL Misc. Service Revenue (Acct 488)						$ 745,000
21							
22	Other Gas Revenues (Acct 495)				251,963		$ 10,000
23							
24	GRAND TOTAL - Misc. & Other Gas Revenues						$ 755,000

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 57 (d)
Witness: Smith

Line No.		(a)	(b)	(c)	(d)	(e)
		Pro-forma Orders Charged		Proposed Rates		TOTAL
		Norm. Units	After Hrs	Normal Hrs	After Hrs	REVENUE
1	**SERVICE CHARGES, PROPOSED RATES**					
2	Meter Set	2,200	10	$28.00	$35.00	$ 61,950
3	Turn On	15,000	25	20.00	25.00	$ 300,625
4	Reconnect Delinquent Service	1,500	30	34.00	40.00	$ 52,200
5	Read	24,000	5	12.00	14.00	$ 288,070
6	Seasonal Charge	60	5	65.00	73.00	$ 4,265
7	Returned Check Charge	3,000	N.A.	23.00		$ 69,000
8	Class 1 EFM Equipment Charge	622	N.A.	105.00		$ 65,310
9	Class 2 EFM Equipment Charge	67	N.A.	245.00		$ 16,415
10	Premises Charge - Requiring Main Extension	0	N.A.	13.09	13.09	$ -
11	Premises Charge - Not Requiring Main Extension	0	N.A.	11.28	11.28	$ -
12	Late Payment Charge	$6,166,082		5%		$ 308,304
13	TOTAL Misc. Service Revenue (Acct 488)					$ 1,166,139
14						
15	Other Gas Revenues (Acct 495)					$ 10,000
16						
17	GRAND TOTAL - Misc. & Other Gas Revenues					$ 1,176,139

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 58 a-d
Witness: Smith

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 11, the Testimony of Gary L. Smith at pages 4-12.

a. Provide the historical data for the three-year period referred to by Mr. Smith on page 6 of his testimony including: (1) the number of customers by customer class; (2) sales volumes, by customer class, adjusted for normal weather; (3) annual changes in volumes for industrial sales and transportation deliveries; and (4) the level of volume migration from sales to transportation volumes.

b. Provide detailed calculations showing the derivation of the adjustment for industrial sales and transportation deliveries referred to by Mr. Smith on page 8, lines 25-28 of his testimony.

c. On page 7, lines 5-6 of his testimony, Mr. Smith refers to "historical growth rates averaging slightly less than 2,000 for the three prior years." To what three years does Mr. Smith refer? How does this statement reconcile with the table on page 12 of his testimony that reflects an average of at least 2,156 for any three-year period included therein?

d. For each year in the five-year period covered in the table on page 12 of Mr. Smith's testimony, provide a breakdown of growth in residential customers between "new construction" and "on-main conversions."

Response:

a. Please refer to the attached summary of the historical data utilized in the preparation of the FY 1999 Budget, PSC DR NO. 1, DR Item 58 (a).

b. Please refer to the response to Data Request 59 (a) which provides detailed calculations showing the derivation of the adjustment for industrial sales and transportation deliveries.

Western Kentucky Gas Company
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DR Item 58 a-d
Witness: Smith

c. The statement in testimony was based on the 12-month ending average number of "customers" reported in the Financial Statements for Fiscal Years 1995 through 1997. Revenue budgets prepared for FY 1998 and 1999 were based on the number of customers within a class, as opposed to total meters in service. The average growth for the stated three year period, was 1,952.

The Table on Page 12 summarizes the total meters in service during the month of December in the years 1994-1998. Please note that the Table mis-identifies the left-hand column as "Fiscal Year"; it should simply state "Year". In other words, the most recent meter count represents December 1998 (which is in the FY of 1999).

d. The only available resource for the information requested are Western's marketing reports, a manual tracking process monitoring residential additions and identifying whether the addition is a newly constructed home or an existing home converted from other fuels. It is difficult to correlate these reports to the customer additions noted in the financial statistics for a variety of reasons. For example, there may be timing differences between the reported addition in the marketing reports vs. the financial reports. The financial statistics rely upon billing system data, recording active accounts - with variances in the level of inactive accounts potentially distorting the correlation to the marketing statistics (which report only customer additions). Notwithstanding these difficulties, Western does review the marketing reports in the revenue budgeting process, concentrating primarily on indicated trends rather than the level of gross additions. Based on these marketing reports, the following additions were noted for FY 1994 to FY 1998 (timing again poses a problem, since the table on page 12 is a snapshot comparing meters in service in December of the noted year).

Fiscal	Residential	
Year	New Construction	Conversions
1994	2,037	1,026
1995	2,236	1,095
1996	1,466	834
1997	1,744	870
1998	1,783	363

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 58 (a)
Witness: Smith

Line No.	(a)	(b)	(c)	(d)
1	HISTORICAL DATA - FY 1999 REVENUE BUDGET:			
2				
3	**Number of Customers by Class, 12 months ending average "customers":**			
4				
5		FY 1995	FY 1996	FY 1997
6	Residential	146,802	147,166	149,331
7	Commercial	16,361	16,731	17,080
8	Industrial	369	335	316
9	Public Authority	1,509	1,534	1,550
10	Total Sales Customers	165,041	165,766	168,277
11				
12	Transportation Customers	17	33	77
13				
14	TOTAL CUSTOMERS	165,058	165,799	168,354
15				
16	**Actual Sales & Transportation Volumes, by Class, in Mcf:**			
17				
18		FY 1995	FY 1996	FY 1997
19	Residential	11,987,742	14,718,174	13,337,468
20	Commercial	5,289,634	6,351,303	5,977,762
21	Industrial	9,992,575	10,725,745	6,128,597
22	Public Authority	1,446,207	1,684,789	1,531,144
23	Unbilled	(55,705)	(24,136)	320,531
24	Total Sales Customers	28,660,453	33,455,875	27,295,502
25				
26	Transportation Customers	17,103,124	16,935,972	22,398,363
27				
28	TOTAL DELIVERIES	45,763,577	50,391,847	49,693,865
29				
30	**Degree-Days:**			
31		FY 1995	FY 1996	FY 1997
32	Actual	4,178	4,610	4,178
33	Normal	4,376	4,376	4,333
34	Percent Normal	95.5%	105.3%	96.4%
35				
36	**Industrial Sales & Transportation / Volume Change from Prior Year:**			
37				
38		FY 1995	FY 1996	FY 1997
39	Industrial Sales	1,226,708	733,170	(4,597,148)
40	Transportation	(395,005)	(167,152)	5,462,391
41	Total Change	831,703	566,018	865,243

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 59 a-c
Witness: Smith

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 11, the Testimony of Gary L. Smith, and Exhibits GLS-1 through GLS-7.

a. Exhibit GLS-3 summarizes the impact of industrial contract adjustments and volume changes. Provide supporting workpapers and narrative descriptions of these changes, by customer (the actual identity of the customers may be omitted and reference made by numbers and/or letters, i.e., – customer 1a).

b. Exhibit GLS-6 summarizes the volume adjustment for declining customer usage. Provide supporting workpapers and narrative descriptions of the calculations made to derive the adjustment.

c. Exhibit GLS-1 shows revenues at current rates reflecting all adjustments to derive test year volumes while Exhibit GLS-7 shows revenues at proposed rates reflecting the same adjustments. Are there any differences in the two exhibits other than: (1) different rates / margins; (2) Alternative Receipt Point volumes and revenues; (3) the amounts shown for Additional Contract Reformation; and (4) the amounts shown for Other Revenue? If yes, identify and explain those differences.

Response:

a. Supporting workpapers relating to Exhibit GLS-3 are attached as PSC DR NO. 1, DR Item 59(a), Sheets 1 through 8. Sheets 1 and 2 summarize the adjustments made for 81 industrial and commercial customers. These sheets also include the description of the specific adjustment for individual customers.

Sheets 3 through 5 identify the affected sales volumes relating to the adjustment, including the detail of the billing block within Western's tariff services. On line 20 of Sheet 5, the adjustments for overrun sales is shown.

Sheets 6 through 8 identify the affected transportation and carriage volumes relating to the adjustment, also providing the details of the billing block affected.

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b. Supporting workpapers relating to Exhibit GLS-6 are attached as PSC DR NO. 1, DR Item 59(b), Sheets 1 through 5. Sheet 1 of the workpapers summarizes the volumetric trend analysis performed for the residential and commercial class from FY 1990 through FY 1998. Descriptions of these calculations are provided below. Sheets 2 through 5 provide the degree-day data from the National Oceanic and Atmospheric Administration ("NOAA") utilized for the study.

Testimony, at pages 12 and 13, provide an overview of the reasons for Western's investigation of average customer usage over the nine-year time period. The intent of the analysis was to determine the reliability of the proposed degree-day composite, consisting of the five First Order weather stations in or near Western's service area. This model was developed to assess the tracking of weather patterns and usage patterns for the temperature-sensitive classes of residential and commercial/public authority. Column "c" estimated the total residential class monthly base load, using the metered volumes for the non-heating months of July and August preceding the Fiscal Year winter period. Column "d" records the total actual residential class deliveries in Western's financial statistics. Column "e" subtracts the estimated base load times twelve months, to estimate the total annual heating load. Column "f", the Normal Heating Load calculation, divides the heating load by the computed % of normal heating degree-days, which is from the financial statistics for the previous degree-day basis and computed from data on Sheets 2 through 5 for the proposed composite degree-day basis. Column "g" adds the normal heating load and the annual base load to estimate the total, weather-normalized volumes for the residential class.

Column "h" records the average residential meters in service for the Fiscal Year from financial statistics. And, Column "i" computes the average, normalized usage per customer. Similarly, Columns "j" through "p" compute the normalize usage per Commercial/Public Authority customer.

Plotting the data graphically, and inserting a "best-fit" line, the slope of the decline indicated by the data was approximately -1.73 Mcf per year for normalized average residential customers, and -3 Mcf per year for Commercial/Public Authority.

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The declining customer usage trend was incorporated in the adjustments from the Fiscal Year 1998 reference period to the Test Year of Calendar Year 2000. The volume adjustment for declining customer usage was labeled "Residential & Commercial Conservation and Energy Efficiency Adjustments", Exhibit GLS-6. For each class the indicated rate of decline was forecast to continue between Fiscal Year 1998 and the Test Year.

c. No, there are no additional differences in the two exhibits other that the four categories identified in the question.

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Line No.	Customer #	Sales Adjustment (Mcf)	Transporation Adjustment (Mcf)	Total Adjustment (Mcf)	Description of Adjustment
	(a)	(b)	(c)	(d)	(e)
1	**Commercial Customers**				
2	1	(13,752)	16,752	3,000	Increased Req. & Contr. Svc. Change
3	2	(14,336)	16,736	2,400	Increased Req. & Contr. Svc. Change
4	3	(49,615)	49,615	-	Contract Service Change
5	4	(10,552)	10,552	-	Contract Service Change
6	5	(15,193)	15,193	-	Contract Service Change
7	6	(16,422)	16,422	-	Contract Service Change
8	7	(23,103)	23,103	-	Contract Service Change
9	8	(7,546)	7,546	-	Contract Service Change
10	9	(18,489)	18,489	-	Contract Service Change
11	10	(3,470)	3,470	-	Contract Service Change
12	11	(15,772)	15,772	-	Contract Service Change
13	12	(14,504)	14,504	-	Contract Service Change
14	13	(75,895)	75,895	-	Contract Service Change
15	14	(7,174)	7,174	-	Contract Service Change
16					
17	**Industrial Customers**				
18	15	1,435	-	1,435	New Customer
19	16	4,739	-	4,739	New Customer
20	17	20,000	-	20,000	New Customer
21	18	6,314	-	6,314	New Customer
22	19	2,783	-	2,783	New Customer
23	20	1,200	-	1,200	New Customer
24	21	-	18,000	18,000	New Customer
25	22	1,200	-	1,200	New Customer
26	23	14,468	-	14,468	New Customer / Annualize Requirements
27	24	900	-	900	New Customer / Annualize Requirements
28	25	-	(29,944)	(29,944)	New Customer / Annualize Requirements
29	26	3,600	-	3,600	New Customer / Annualize Requirements
30	27	7,000	-	7,000	New Customer / Annualize Requirements
31	28	(2,822)	40,021	37,199	New Customer & Contr. Svc. Change
32	29	72,545	-	72,545	New Customer & Contr. Svc. Change
33	30	28,000	-	28,000	Annualize Increased Requirements
34	31	(12,229)	24,149	11,920	Increased Req. & Contr. Svc. Change
35	32	(49,883)	85,198	35,315	Increased Req. & Contr. Svc. Change
36	33	(18,770)	23,570	4,800	Increased Req. & Contr. Svc. Change
37	34	(10,549)	11,749	1,200	Increased Req. & Contr. Svc. Change
38	35	(146)	12,146	12,000	Increased Req. & Contr. Svc. Change
39	36	(25,000)	-	(25,000)	Annualize Reduced Requirements
40	37	-	(96,000)	(96,000)	Annualize Reduced Requirements
41	38	-	(310,532)	(310,532)	Annualize Reduced Requirements
42	39	-	(98,086)	(98,086)	Annualize Reduced Requirements
43	40	-	(853,169)	(853,169)	Annualize Reduced Requirements
44	41	(183,311)	-	(183,311)	Annualize Reduced Requirements
45	42	(27,974)	16,760	(11,214)	Reduced Req. & Contr. Svc. Change
46	43	(10,727)	5,185	(5,542)	Reduced Req. & Contr. Svc. Change
47	44	(28,950)	-	(28,950)	Plant Closing
48	45	-	(91,465)	(91,465)	Plant Closing
49	46	(1,938)	-	(1,938)	Plant Closing
50	47	(35,541)	-	(35,541)	Plant Closing
51	48	-	(50,125)	(50,125)	Plant Closing
52	49	(47,140)	47,140	-	Contract Service Change
53	50	(39,401)	39,401	-	Contract Service Change
54	51	(11,694)	11,694	-	Contract Service Change
55	52	(13,938)	13,938	-	Contract Service Change
56	53	(64,200)	64,200	-	Contract Service Change
57	54	(13,970)	13,970	-	Contract Service Change
58	55	(20,806)	20,806	-	Contract Service Change
59	56	(8,407)	8,407	-	Contract Service Change
60	57	(25,811)	25,811	-	Contract Service Change

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Line No.	Customer	Sales Adjustment (Mcf)	Transporation Adjustment (Mcf)	Total Adjustment (Mcf)	Description of Adjustment
	(a)	(b)	(c)	(d)	(e)
61	58	(32,829)	32,829	-	Contract Service Change
62	59	(6,309)	6,309	-	Contract Service Change
63	60	(5,787)	5,787	-	Contract Service Change
1	61	(19,718)	19,718	-	Contract Service Change
2	62	(9,530)	9,530	-	Contract Service Change
3	63	(14,346)	14,346	-	Contract Service Change
4	64	(49,124)	49,124	-	Contract Service Change
5	65	(34,770)	34,770	-	Contract Service Change
6	66	(13,098)	13,098	-	Contract Service Change
7	67	(10,682)	10,682	-	Contract Service Change
8	68	(27,808)	27,808	-	Contract Service Change
9	69	(4,005)	4,005	-	Contract Service Change
10	70	(53,834)	53,834	-	Contract Service Change
11	71	(4,381)	4,381	-	Contract Service Change
12	72	(5,194)	5,194	-	Contract Service Change
13	73	(69,441)	69,441	-	Contract Service Change
14	74	(36,555)	36,555	-	Contract Service Change
15					
16	**Special Contracts**				
17	75	-	-	-	Contract Rate Change
18	76	-	-	-	Contract Rate Change
19	77	-	120,000	120,000	Increased Req. & Contr. Rate Change
20	78	-	60,000	60,000	Annualize Increased Requirements
21	79	-	48,000	48,000	Annualize Increased Requirements
22	80	-	(180,000)	(180,000)	Annualize Reduced Requirements
23	81	(8,000)	8,000	-	
24					
25	**Overrun Adjustment**	(178,065)	178,065	-	
26					
27					
28	TOTAL	(1,358,322)	(124,477)	(1,482,799)	

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Line No.	Customer #	G-1 Block 1	G-1 Block 2	G-1 Block 3	G-2 Block 1	G-2 Block 2	LVS-1 Block 1	LVS-1 Block 2	LVS-1 Block 3	LVS-2 Block 1	LVS-2 Block 2	TOTAL SALES
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Commercial Customers**											
2	1	(2,417)	(11,335)									(13,752)
3	2	(1,200)	(13,136)									(14,336)
4	3	(2,774)	(46,841)									(49,615)
5	4	(3,600)	(6,952)									(10,552)
6	5	(3,600)	(11,593)									(15,193)
7	6	(3,600)	(12,822)									(16,422)
8	7	(3,600)	(19,503)									(23,103)
9	8	(1,532)	(6,014)									(7,546)
10	9	(3,300)	(15,189)									(18,489)
11	10	(1,915)	(1,555)									(3,470)
12	11	(2,100)	(13,672)									(15,772)
13	12	(2,700)	(11,804)									(14,504)
14	13									(75,895)		(75,895)
15	14				(7,174)							(7,174)
16	Sub-total - Commercial	(32,338)	(170,416)	-	(7,174)	-	-	-	-	(75,895)	-	(285,823)
17												
18	**Industrial Customers**											
19	15	1,435										1,435
20	16	2,699	2,040									4,739
21	17	3,600	16,400									20,000
22	18	2,600	3,714									6,314
23	19	1,850	933									2,783
24	20	1,200										1,200
25	21											-
26	22	1,200										1,200
27	23	2,700	11,768									14,468
28	24	873	27									900
29	25											-
30	26	1,700	1,900									3,600
31	27	900	6,100									7,000
32	28	(2,024)	(798)									(2,822)
33	29				70,158	2,387						72,545
34	30				28,000							28,000
35	31						(300)	(11,929)				(12,229)
36	32	(3,600)	(46,283)									(49,883)
37	33	(3,600)	(15,170)									(18,770)
38	34	(1,800)	(8,749)									(10,549)

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Line No.	Customer	G-1 Block 1	G-1 Block 2	G-1 Block 3	G-2 Block 1	G-2 Block 2	LVS-1 Block 1	LVS-1 Block 2	LVS-1 Block 3	LVS-2 Block 1	LVS-2 Block 2	TOTAL SALES
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	35				(146)							(146)
2	36				(13,165)	(11,835)						(25,000)
3	37											-
4	38											-
5	39											-
6	40											-
7	41				(109,400)	(73,911)						(183,311)
8	42	(1,500)	(26,474)									(27,974)
9	43	(1,500)	(9,227)									(10,727)
10	44	(1,920)	(4,254)			(22,776)						(28,950)
11	45											-
12	46	(1,668)	(270)									(1,938)
13	47				(35,541)							(35,541)
14	48											-
15	49	(3,600)	(43,540)									(47,140)
16	50	(3,600)	(35,801)									(39,401)
17	51	(3,367)	(8,327)									(11,694)
18	52	(3,600)	(10,338)									(13,938)
19	53	(3,600)	(60,600)									(64,200)
20	54	(3,600)	(10,370)									(13,970)
21	55	(3,600)	(17,206)									(20,806)
22	56	(3,300)	(5,107)									(8,407)
23	57	(2,700)	(23,111)									(25,811)
24	58	(2,400)	(30,429)									(32,829)
25	59	(1,200)	(5,109)									(6,309)
26	60	(1,500)	(4,287)									(5,787)
27	61	(1,800)	(17,918)									(19,718)
28	62	(1,200)	(8,330)									(9,530)
29	63	(3,600)	(10,746)									(14,346)
30	64				(35,656)	(13,468)						(49,124)
31	65				(34,770)							(34,770)
32	66				(13,098)							(13,098)
33	67				(10,682)							(10,682)
34	68	(2,700)	(25,108)									(27,808)

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Line No.	Customer	G-1 Block 1	G-1 Block 2	G-1 Block 3	G-2 Block 1	G-2 Block 2	LVS-1 Block 1	LVS-1 Block 2	LVS-1 Block 3	LVS-2 Block 1	LVS-2 Block 2	TOTAL SALES
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	69	(1,200)	(2,805)									(4,005)
2	70						(1,200)	(52,634)				(53,834)
3	71									(4,381)		(4,381)
4	72	(2,100)	(2,061)		(1,033)							(5,194)
5	73	(1,703)	(13,826)		(53,912)							(69,441)
6	74				(36,555)							(36,555)
7	Sub-total - Commercial	(47,225)	(403,362)	-	(245,800)	(119,603)	(1,500)	(64,563)	-	(4,381)	-	(886,434)
8												
9	**Special Contracts**											
10	75											-
11	76											-
12	77											-
13	78											-
14	79											-
15	80											-
16	81					(8,000)						(8,000)
17												
18	SUBTOTAL	(79,563)	(573,778)	-	(252,974)	(127,603)	(1,500)	(64,563)	-	(80,276)	-	(1,180,257)
19												
20	**Overrun Adjustment**	T-4 OR	T-4 OR	T-4 OR	T-3 OR	T-3 OR						
21		Block 1	Block 2	Block 3	Block 1	Block 2						
22												
23	Overrun Adjustment	(11,639)	(25,410)	-	(141,016)	-						(178,065)
24												
25	**TOTAL SALES**											(1,358,322)

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Line No.	Customer #	T-2/G-1 Block 1	T-2/G-1 Block 2	T-2/G-1 Block 3	T-2/G-2 Block 1	T-2/G-2 Block 2	T-3 Block 1	T-3 Block 2	T-4 Block 1	T-4 Block 2	T-4 Block 3	Special Contract	TOTAL TRANSP.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	**Commercial Customers**												
2	1								3,600	13,152			16,752
3	2								1,200	15,536			16,736
4	3								2,774	46,841			49,615
5	4								3,600	6,952			10,552
6	5								3,600	11,593			15,193
7	6								3,600	12,822			16,422
8	7								3,600	19,503			23,103
9	8	(2,068)	(17,954)						3,600	23,968			7,546
10	9								3,300	15,189			18,489
11	10	(1,685)	(6,055)						3,600	7,610			3,470
12	11				15,772								15,772
13	12						14,504						14,504
14	13						75,895						75,895
15	14						7,174						7,174
16													
17	**Industrial Customers**												
18	15												-
19	16												-
20	17												-
21	18												-
22	19												-
23	20												-
24	21								3,600	14,400			18,000
25	22												-
26	23												-
27	24												-
28	25								(3,300)	(26,644)			(29,944)
29	26												-
30	27												-
31	28								3,600	36,421			40,021
32	29												-
33	30												-
34	31								300	23,849			24,149
35	32								3,600	81,598			85,198
36	33								3,600	19,970			23,570
37	34								1,800	9,949			11,749

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Line No.	Customer #	T-2/G-1 Block 1	T-2/G-1 Block 2	T-2/G-1 Block 3	T-2/G-2 Block 1	T-2/G-2 Block 2	T-3 Block 1	T-3 Block 2	T-4 Block 1	T-4 Block 2	T-4 Block 3	Special Contract	TOTAL TRANSP.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	35				(37,117)		49,263						12,146
2	36												-
3	37							(96,000)					(96,000)
4	38										(310,532)		(310,532)
5	39						(98,086)						(98,086)
6	40						(90,782)	(745,169)		(17,218)			(853,169)
7	41												-
8	42								1,500	15,260			16,760
9	43								1,500	3,685			5,185
10	44												-
11	45							(91,465)					(91,465)
12	46												-
13	47												-
14	48								(3,600)	(46,525)			(50,125)
15	49								3,600	43,540			47,140
16	50								3,600	35,801			39,401
17	51								3,367	8,327			11,694
18	52								3,600	10,338			13,938
19	53								3,600	60,600			64,200
20	54								3,600	10,370			13,970
21	55								3,600	17,206			20,806
22	56								3,300	5,107			8,407
23	57								2,700	23,111			25,811
24	58								2,400	30,429			32,829
25	59								1,200	5,109			6,309
26	60								1,500	4,287			5,787
27	61								1,800	17,918			19,718
28	62								1,200	8,330			9,530
29	63								3,600	10,746			14,346
30	64				(144,344)	(58,376)	180,000	71,844					49,124
31	65				(6,198)		40,968						34,770
32	66				(21,036)		34,134						13,098
33	67				(36,819)		47,501						10,682
34	68						27,808						27,808

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Line No.	Customer #	T-2/G-1 Block 1	T-2/G-1 Block 2	T-2/G-1 Block 3	T-2/G-2 Block 1	T-2/G-2 Block 2	T-3 Block 1	T-3 Block 2	T-4 Block 1	T-4 Block 2	T-4 Block 3	Special Contract	TOTAL TRANSP.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
35	69	4,005											4,005
36	70								1,200	52,634			53,834
37	71						4,381						4,381
38	72						1,033		2,100	2,061			5,194
39	73						53,912		1,703	13,826			69,441
40	74						36,555						36,555
41													(649,765)
42	**Special Contracts**												
43	75											-	-
44	76											-	-
45	77											120,000	120,000
46	78											60,000	60,000
47	79											48,000	48,000
48	80											(180,000)	(180,000)
49	81											8,000	8,000
50													
51	**Overrun Adjustment**						95,286	-	11,639	25,410	-	45,730	178,065
52													
53													
54	TOTAL	252	(24,009)	-	(229,742)	(58,376)	479,546	(860,790)	104,383	673,061	(310,532)	101,730	(774,241)
55													

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Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	**Degree Day Basis: Former WKG Method**															
2																
3			RESIDENTIAL VOLUMES							COMMERCIAL & PUBLIC AUTHORITY VOLUMES						
4		% Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal
5		DD	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust
6																
7	FY 90	90.3%	256,004	12,594,525	9,522,477	10,544,568	13,616,616	133,588	101.93	189,347	6,401,691	4,129,527	4,572,768	6,844,932	16,012	427.49
8	FY 91	81.3%	257,793	11,786,006	8,692,490	10,697,120	13,790,636	135,612	101.69	198,297	5,944,397	3,564,839	4,386,949	6,766,507	16,158	418.77
9	FY 92	88.2%	259,035	12,415,482	9,307,068	10,554,181	13,662,595	140,975	96.92	171,364	6,109,353	4,052,991	4,596,077	6,652,439	16,938	392.75
10	FY 93	95.5%	269,910	13,288,027	10,049,107	10,527,752	13,766,672	143,120	96.19	204,054	6,906,207	4,457,565	4,669,881	7,118,523	17,549	405.64
11	FY 94	100.2%	252,128	13,861,028	10,835,498	10,813,038	13,838,568	145,689	94.99	185,005	7,447,460	5,227,406	5,216,571	7,436,625	18,148	409.78
12	FY 95	87.5%	247,727	11,987,742	9,015,024	10,301,186	13,273,904	149,014	89.08	229,197	6,735,841	3,985,477	4,554,080	7,304,444	18,495	394.94
13	FY 96	106.4%	248,341	14,718,174	11,738,085	11,032,781	14,012,870	151,378	92.57	225,049	8,036,092	5,335,504	5,014,911	7,715,499	18,885	408.55
14	FY 97	96.4%	248,955	13,337,468	10,350,008	10,733,984	13,721,444	153,720	89.26	220,901	7,508,906	4,858,094	5,038,325	7,689,137	19,248	399.48
15	FY 98	87.0%	251,963	12,561,176	9,537,626	10,959,038	13,982,588	155,846	89.72	213,619	7,066,080	4,502,652	5,173,692	7,737,120	19,620	394.35
16																
17	**Degree Day Basis: Proposed WKG Method**															
18																
19			RESIDENTIAL VOLUMES							COMMERCIAL & PUBLIC AUTHORITY VOLUMES						
20		% Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal	Actual	Total Act	Annual	Normal	Normal	Meters	Normal
21		DD	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust	BL/mo	Volume	Heating Load	Heating Load	Total	in Svc	per Cust
22																
23	FY 90	92.5%	256,004	12,594,525	9,522,477	10,290,725	13,362,773	133,588	100.03	189,347	6,401,691	4,129,527	4,462,686	6,734,850	16,012	420.61
24	FY 91	85.0%	257,793	11,786,006	8,692,490	10,223,687	13,317,203	135,612	98.20	198,297	5,944,397	3,564,839	4,192,792	6,572,350	16,158	406.76
25	FY 92	89.1%	259,035	12,415,482	9,307,068	10,442,781	13,551,195	140,975	96.12	171,364	6,109,353	4,052,991	4,547,565	6,603,927	16,938	389.89
26	FY 93	96.3%	269,910	13,288,027	10,049,107	10,438,756	13,677,676	143,120	95.57	204,054	6,906,207	4,457,565	4,630,405	7,079,047	17,549	403.39
27	FY 94	101.3%	252,128	13,861,028	10,835,498	10,695,033	13,720,563	145,689	94.18	185,005	7,447,460	5,227,406	5,159,641	7,379,695	18,148	406.64
28	FY 95	84.4%	247,727	11,987,742	9,015,024	10,675,363	13,648,081	149,014	91.59	229,197	6,735,841	3,985,477	4,719,501	7,469,865	18,495	403.89
29	FY 96	109.4%	248,341	14,718,174	11,738,085	10,729,421	13,709,510	151,378	90.56	225,049	8,036,092	5,335,504	4,877,019	7,577,607	18,885	401.25
30	FY 97	99.4%	248,955	13,337,468	10,350,008	10,409,973	13,397,433	153,720	87.15	220,901	7,508,906	4,858,094	4,886,241	7,537,053	19,248	391.58
31	FY 98	92.5%	251,963	12,561,176	9,537,626	10,314,801	13,338,351	155,846	85.59	213,619	7,066,080	4,502,652	4,869,551	7,432,979	19,620	378.85
32																
33																
34	BL/month is based on actual metered volumes for months of July and August preceeding the stated Fiscal Year winter period.															

Western Kentucky Gas Company
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DR Item 59 (b)
Witness: Smith

Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
	% Allocation	15.61%	2.80%	37.92%	22.22%	21.44%		
1	**Oct**	287	254	228	266	195	239	239
2	**Nov**	570	537	513	564	450	520	515
3	**Dec**	902	871	859	924	760	859	859
4	**Jan**	1060	1032	1004	1082	893	1,007	1,006
5	**Feb**	854	820	787	857	689	793	793
6	**Mar**	611	580	550	595	469	553	556
7	**Apr**	312	273	231	273	193	246	242
8	**May**	135	105	83	114	59	93	92
9	**Jun**	5	6	0	0	0	1	2
10	**Jul**	0	0	0	0	0	-	-
11	**Aug**	0	0	0	0	0	-	-
12	**Sep**	47	36	24	33	21	29	29
13								
14	**Normal**	4783	4514	4279	4708	3729	4,340	4,333

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Witness: Smith

Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
1	Oct-89	267	230	193	225	158	205	
2	Nov-89	592	539	488	577	408	508	
3	Dec-89	1297	1222	1165	1297	1095	1,202	
4	Jan-90	720	672	651	707	590	662	
5	Feb-90	608	574	534	603	422	538	
6	Mar-90	505	445	438	487	373	446	
7	Apr-90	378	320	313	358	245	319	
8	May-90	128	82	89	97	65	92	
9	Jun-90	17	13	10	15	1	10	
10	Jul-90	0	0	0	2	0	-	
11	Aug-90	3	0	1	1	0	1	
12	Sep-90	57	34	28	35	21	33	
13								
14	FY 1990	4572	4131	3910	4404	3378	4,016	3,913
15	% Norm						92.5%	90.3%
16								
17	Oct-90	288	229	273	291	195	261	
18	Nov-90	453	387	352	432	323	380	
19	Dec-90	757	745	771	828	654	756	
20	Jan-91	955	949	949	1037	791	936	
21	Feb-91	719	677	642	702	586	656	
22	Mar-91	544	482	429	528	402	465	
23	Apr-91	215	167	119	191	80	143	
24	May-91	34	27	18	42	9	24	
25	Jun-91	0	0	0	0	0	-	
26	Jul-91	0	0	0	0	0	-	
27	Aug-91	0	0	0	0	0	-	
28	Sep-91	77	52	72	88	42	69	
29								
30	FY 1991	4042	3715	3625	4139	3082	3,690	3,521
31	% Norm						85.0%	81.3%
32								
33	Oct-91	230	168	190	227	166	199	
34	Nov-91	642	590	585	647	535	597	
35	Dec-91	765	725	709	791	628	719	
36	Jan-92	915	855	827	913	768	848	
37	Feb-92	682	610	556	673	544	601	
38	Mar-92	600	523	470	549	456	506	
39	Apr-92	293	244	228	259	217	243	
40	May-92	159	124	86	118	85	105	
41	Jun-92	17	8	5	10	2	7	
42	Jul-92	0	0	0	0	0	-	
43	Aug-92	5	0	0	0	0	1	
44	Sep-92	64	40	39	46	26	42	
45								
46	FY 1992	4372	3887	3695	4233	3427	3,868	3,821
47	% Norm						89.1%	88.2%

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Witness: Smith

Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
1	Oct-92	288	219	203	236	181	219	
2	Nov-92	566	505	502	538	461	511	
3	Dec-92	863	813	808	875	731	815	
4	Jan-93	847	819	818	879	717	814	
5	Feb-93	884	859	781	892	713	809	
6	Mar-93	705	644	565	671	552	610	
7	Apr-93	363	299	279	322	252	296	
8	May-93	64	44	40	46	32	43	
9	Jun-93	27	18	8	12	4	11	
10	Jul-93	0	0	0	0	0	-	
11	Aug-93	0	0	0	0	0	-	
12	Sep-93	67	48	54	55	27	50	
13								
14	FY 1993	4674	4268	4058	4526	3670	4,178	4,136
15	% Norm						96.3%	95.5%
16								
17	Oct-93	313	289	293	296	227	283	
18	Nov-93	608	572	581	600	528	578	
19	Dec-93	922	875	812	879	759	834	
20	Jan-94	1231	1180	1110	1164	974	1,114	
21	Feb-94	783	752	705	770	585	707	
22	Mar-94	658	602	531	603	437	549	
23	Apr-94	229	189	185	213	134	187	
24	May-94	185	122	93	96	90	108	
25	Jun-94	3	3	0	5	0	2	
26	Jul-94	0	0	0	0	0	-	
27	Aug-94	3	0	0	0	0	-	
28	Sep-94	37	20	38	44	21	35	
29								
30	FY 1994	4972	4604	4348	4670	3755	4,397	4,342
31	% Norm						101.3%	100.2%
32								
33	Oct-94	232	186	186	180	144	183	
34	Nov-94	425	384	372	403	316	375	
35	Dec-94	730	696	691	702	605	681	
36	Jan-95	960	904	864	922	814	882	
37	Feb-95	877	800	761	804	683	773	
38	Mar-95	545	471	415	465	344	433	
39	Apr-95	298	236	207	229	175	220	
40	May-95	108	72	64	62	42	66	
41	Jun-95	2	0	0	0	0	-	
42	Jul-95	0	0	0	0	0	-	
43	Aug-95	0	0	0	0	0	-	
44	Sep-95	65	48	61	50	31	52	
45								
46	FY 1995	4242	3797	3621	3817	3154	3,665	3,792
47	% Norm						84.4%	87.5%

Western Kentucky Gas Company
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DR Item 59 (b)
Witness: Smith

Line No.	(a)	(b) Lexington	(c) Louisville	(d) Paducah	(e) Evansville	(f) Nashville	(g) Proposed	(h) Former
1	Oct-95	254	192	197	168	184	197	
2	Nov-95	755	693	686	710	624	689	
3	Dec-95	983	915	874	904	783	879	
4	Jan-96	1048	1002	994	1048	886	991	
5	Feb-96	844	782	782	829	702	785	
6	Mar-96	799	738	739	819	626	742	
7	Apr-96	426	353	337	407	292	357	
8	May-96	96	66	46	75	32	58	
9	Jun-96	8	2	3	5	0	4	
10	Jul-96	0		0	0	0	-	
11	Aug-96	0		0	0	0	-	
12	Sep-96	64		40	70	25	46	
13								
14	FY 1996	5277	4743	4698	5035	4154	4,748	4,610
15	% Norm						109.4%	106.4%
16								
17	Oct-96	268	202	216	253	160	220	
18	Nov-96	750	689	656	732	572	670	
19	Dec-96	784	741	760	830	634	752	
20	Jan-97	1025	1005	1019	1108	851	1,003	
21	Feb-97	670	634	625	702	538	631	
22	Mar-97	576	472	455	542	357	473	
23	Apr-97	471	366	372	428	319	388	
24	May-97	233	140	129	172	107	150	
25	Jun-97	31	12	5	11	4	10	
26	Jul-97	1	0	0	0	0	-	
27	Aug-97	3	0	0	0	0	-	
28	Sep-97	39	9	18	24	0	18	
29								
30	FY 1997	4851	4270	4255	4802	3542	4,315	4,178
31	% Norm						99.4%	96.4%
32								
33	Oct-97	321	263	292	300	227	284	
34	Nov-97	698	621	670	692	576	658	
35	Dec-97	904	854	860	922	785	864	
36	Jan-98	745	696	750	786	622	728	
37	Feb-98	666	594	577	635	527	594	
38	Mar-98	614	561	576	604	505	573	
39	Apr-98	331	261	255	301	209	267	
40	May-98	46	27	26	30	19	29	
41	Jun-98	24	15	9	20	5	13	
42	Jul-98	0	0	0	0	0	-	
43	Aug-98	0	0	0	0	0	-	
44	Sep-98	8	0	2	4	0	3	
45								
46	FY 1998	4357	3892	4017	4294	3475	4,013	3,771
47	% Norm						92.5%	87.0%

09

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 60
Witness: D. Donald A. Murry

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 8, the Testimony of Dr. Donald A. Murry.

a. Page 6, lines 20 through 22, indicates that the Commission should make allowances for the added risk of the inclusion of short-term debt in the capital structure. In what way should the Commission make such an allowance?

b. Page 5, beginning on line 17, indicates that Atmos raises capital for Western's operations. Is this beneficial to Western? If so, should the Commission make allowances for Western's ability to access this capital source? Would it be more risky for Western if it had to raise capital itself for its operations?

c. Provide an explanation of why each company in the group of comparative companies is considered to be a viable comparison to Atmos.

d. Provide the most recently approved return on equity for each of the comparable companies, along with the date each was approved.

e. Do any of the comparable companies use a weather normalization adjustment, a premises charge, or a margin loss recovery mechanism to stabilize their earnings? If so, which ones?

f. What effect would the implementation of a weather normalization adjustment have on Western's financial risk?

g. What effect would the implementation of a premises charge have on Western's financial risk?

h. What effect would a margin loss recovery mechanism have on Western's financial risk?

Response:

a. The Commission should allow for the risk of short-term interest rate increase.

b. Atmos is several times large than Western Kentucky Gas, and Atmos has a greater presence in the financial market than a stand-alone Western Kentucky Gas would have. As a result, Western Kentucky Gas would have a higher cost of capital as a stand-alone company. Please see page 20, lines 1-5 of the Direct Testimony of Donald A. Murry.

c. The Moody's companies are recognized by financial analysts as representative of the gas distribution sector. Please see page 8, lines 8-15 of the Direct Testimony of Donald A. Murry.

d. Dr. Murry does not have the requested records.

e. Dr. Murry does not know if any of the comparable companies use a weather normalization adjustment, premises charge or margin loss recovery mechanism to stabilize their earnings.

f. Generally, the weather normalization adjustment reduces the instability of revenues. However, revenue stability may or may not affect a company's business risk. Please see page 34, lines 1-30 and page 35, lines 1-30 of Mr. Gary L. Smith's Direct Testimony.

g. As a mechanism to control the market risks of gas distribution companies associated with continued residential growth, a premises charge should reduce the business risk of the company slightly. In this case, the effect upon the expectations of investors will be inconsequential. Please see page 38, lines 11-18 of Mr. Gary L. Smith's Direct testimony.

h. As a small distribution company, Western Kentucky Gas faces an inordinate business risk in competitive markets, and the margin loss recovery is likely to reduce the business risk of a company somewhat. However, in the case of Western Kentucky Gas, the impact on revenues may not be sufficient to influence capital costs. Please see page 29, line 19 through page 31, line 26 of Mr. Gary L. Smith's Direct Testimony.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 61 a-c
Witness: Smith

Data Request:

Refer to Volume 10 of 10 of the Application, Tab 4, Summary of Jurisdictional Adjustments by Major Accounts, Schedule D-1, Sheet 1 of 4 and Schedule D-2.1, Sheets 1 and 2.

a. Provide supporting workpapers for the revenue and gas purchases adjustments on these schedules, or reference where provided if already included in the application or in response to other requests contained in this Order.

b. Provide narrative descriptions of the workpapers provided in response to part (a) above.

c. Explain in detail the reasons for the proposed reductions to Service Revenues and Other Gas Service Revenues.

Response:

a. Please reference the testimony of Mr. Gary Smith, Volume 2 of 10, Tab 11 of the application, at pages 4 through 14, describe in detail the processes employed in the development of revenue forecasts for the Base Period and Test Period. As evidenced by the discussion in the testimony, the FY 2000 budget, although similar in process to the FY 1999 budget, does not build from the prior budget. Different degree-day bases were utilized, recognition of declining customer demand (previously not quantified), and several other variances present difficulties in analyzing the "gaps" between the periods.
FR 10(10)(m) details the monthly and annual comparisons of the Base Period and Test Period. As is noted the Base Period consists of 6 months actual data and six months of the FY 1999 budget. FR 10(10)(d)2.1 provides a narrative summary of key components of "adjustments" or differences between the Base Period and Test Period. No workpapers were prepared to isolate the individual components within these differences.

Western Kentucky Gas Company
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DR Item 61 a-c
Witness: Smith

b. Not applicable. See response to part a. of this Data Request.

c. The projection of Test Year Service Revenues and Other Gas Revenues was based solely on recent levels of service activities. Reference workpapers provided in response to DR Item 57(d), Sheet 1 of 2, for details of the actual orders charged for FY 1998.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 62
Witness: Gruber

Data Request:

. Refer to Volume 2 of 10 of the Application, Tab 1, the Testimony of Conrad E. Gruber, specifically, the table on page 11 which denotes Western's operating and maintenance cost efficiencies in comparison to industry averages.

a. Provide copies of the A.G. Edwards study cited and a detailed schedule of Western's operating and maintenance expenses, identified by fiscal year ("FY"), used to determine Western's Costs per Meter as shown in the table.

b. Provide a detailed schedule of Western's gas utility employees by job classification for the period used to determine Western's number of employees per 1,000 customers as shown in the table.

c. Provide documentation used for external reporting purposes to substantiate the number of meters in service and thousands of customers served for the period represented by the table.

Response:

a. The A.G. Edwards Study is attached. Atmos Energy is one of the large gas LDCs referenced in the study. The data on Atmos apparently reflects O&M costs which pre-date the merger of Atmos with United Cities Gas Company and the subsequent savings achieved through the significant downsizing of UCG and the overall reorganization of Atmos. The benefits of the merger and Atmos reorganization on O&M costs did not begin to materialize until 1998 and are clearly not reflected in the 1997 A.G. Edwards study.

Schedule A details Western's actual O&M expenses and comparable meter count for April 98 – March 99, the most recent 12-month period data available at filing, as shown in Mr. Gruber's testimony. (Mr. Gruber's testimony misidentifies this number as representing the base period in this case.)

b. Schedule B details Western's April 98 – March 99 employees, by job classification, and comparable customer meter count to determine the employees per 1000 customers (meters) ratio shown in Mr. Gruber's testimony. An appropriate allocation of Shared Services employees has also been reflected in Schedule B.

c. Western's customer meter count and employees as used for the table in Mr. Gruber's testimony are not available through documents used for external reporting purposes. However, this does not nullify the validity of these numbers for comparison of Western to the most recently published industry data. The customer meter count was obtained from Western's Financial Statements (the Gray Book, published monthly, see FR 10(9)(n)) and the employee data was obtained from Western's Human Resource system (see response to DR item 69).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 62
Schedule A

	1998 April	1998 May	1998 June	1998 July	1998 August	1998 September	1998 October	1998 November	1998 December	1999 January	1999 February	1999 March	12 months Total
WKG Operating Expense	$ 1,271,845	1,247,059	1,053,730	1,104,618	1,056,176	1,230,606	1,356,318	1,008,371	1,005,815	1,153,522	784,473	989,293	$ 13,261,826
WKG Maintainence Expense	87,898	91,296	86,190	72,553	59,837	114,043	38,367	71,399	69,933	80,949	42,677	75,604	890,746
	1,359,743	1,338,355	1,139,920	1,177,171	1,116,013	1,344,649	1,394,685	1,079,770	1,075,748	1,234,471	827,150	1,064,897	14,152,572
Shared Services O&M	274,863	256,233	404,568	259,675	192,045	679,605	738,973	684,764	545,230	679,475	954,181	610,295	6,279,907
	$ 1,634,606	1,594,588	1,544,488	1,436,846	1,308,058	2,024,254	2,133,658	1,764,534	1,620,978	1,913,946	1,781,331	1,675,192	$ 20,432,479
Customer Meters	175,729	175,658	175,827	175,663	175,717	176,128	176,808	177,549	178,098	178,391	178,595	178,715	2,122,878

12 mos. O&M/	$ 20,432,479
12 mos. Average # of meters	176,907
12 mos. O&M per customer	$ 115

Western Kentucky Gas Company
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DR Item 62
Schedule B

Western Kentucky Gas Company
Job Titles

Job Title	No. of Employees
Computer Mapping Technician	3
Construction Operator	13
Corrosion Control Coordinator	1
Corrosion Control Technician	6
Crew Foreman	23
Emp Development & Safety Coordinator	2
Engineering Technician	5
Executive Assistant	1
Field Operator	8
Field Support Analyst	2
Financial Analyst	1
Laborer	2
Large Volume Sales Engineer	1
Manager Engineering Services	2
Manager Information Services	1
Manager Public Affairs	1
Manager Sales	1
Measurement Specialist	2
Measurement Supervisor	1
Meter Reader	9
Operations Assistant	21
Operations Manager	5
Operations Specialist	12
Operations Supervisor	14
President	1
Sales Representative I	2
Sales Representative II	4
Service Specialist	11
Service Technician	11
Sr. Administrative Assistant	4

Western Kentucky Gas Company
Case No. 99-070
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DR Item 62
Schedule B

Western Kentucky Gas Company
Job Titles

Job Title	No. of Employees
Sr. Construction Operator	20
Sr. Service Technician	51
Storage Foreman	2
Storage Technician	2
Town Operator	9
VP & Controller	1
VP Eastern Region	1
VP Human Resources	1
VP Marketing	1
VP Rates & Regulatory Affairs	1
VP Technical Services	1
VP Western Region	1
Warehouse Coordinator	1
Warehouse Technician	5
Total WKG Employees	267
Allocation of Shared Services Employees	75
	342

A.G.Edwards

Gas Utilities: Annual Productivity Study

DECEMBER 14, 1998

Michael C. Heim, CFA (314) 955-3272
Daniel M. Fidell (314) 955-5540
R. Michael Creager, *Associate Analyst*

Introduction

As both the natural gas and electric utility industries move toward market-based competition, the success of individual natural gas distributors depends more and more on their ability to control costs. In this increasingly competitive marketplace, traditional local distribution companies (LDCs) face competition from a growing number of players. As retail unbundling unfolds, some LDCs will be competing with independent gas marketers for the supply of the gas commodity. Thus, the ability of the gas utility to deliver gas to the customer efficiently and inexpensively will become even more important as the LDC attempts to build and maintain customer loyalty. Natural gas distributors will likely face increasing competition from electric utilities as deregulation in that industry results in lower electric rates. In addition, the gas distributors will continue to face price competition from distributors of alternative fuels such as heating oil and propane. Indeed, the depressed oil prices over the last 12 months have led to a price advantage for heating oil over natural gas in many areas in the northeast.

A more competitive environment, however, will also present opportunities for those natural gas distributors that are able to effectively control costs. For example, some states are offering incentive- or performance-based rates that reward efficiently operated utilities by allowing them to keep additional profits above an established benchmark. We also expect the consolidation trend to continue with electric utilities seeking to diversify and gas utilities attempting to gain economies of scale. In this atmosphere, we expect a larger premium to be paid for those gas utilities that have been able to demonstrate a history of operating efficiency.

The goal of this report is to identify and analyze the key productivity measures that can provide some evidence of how the industry has positioned itself to survive in this rapidly changing environment. The results continue to support the relative advantages enjoyed by large utilities in each of the productivity categories studied. Current favorably rated stocks in the Large Distributor group that performed well in our study include NICOR Inc. (GAS-40 7/16-NYSE—rated Accumulate/Conservative) and Northwest Natural Gas (NWNG-27 5/8-Nasdaq—rated Accumulate/Conservative). In the Integrated and Diversified categories, Questar (STR-17 7/8-NYSE—rated Accumulate/Conservative) and CMS Energy Class G (CPG-25 1/8-NYSE—rated Accumulate/Conservative) were among those with favorable productivity results relative to their peers.

Methodology

This study examines the fiscal 1997 results of the 41 companies in the A.G. Edwards Gas Utility Index. (See Figures 1 and 2 on pages 2 and 3.) The index divides the universe of companies into four groups: Small Distributors, Large Distributors, Integrated Utilities and Diversified Utilities. The Small Distributors group is made up of the local distribution companies (LDCs) with market capitalizations in the range of $100 million to $400 million and relatively light daily trading volume. The Large Distributors group consists of the larger LDCs with a market capitalization range of $400 million to $2 billion. The Integrated Utilities group consists of those companies that have become involved in multiple segments of the

(continued on page 4)

FIGURE 1 **Fiscal 1997 Productivity Statistics**

Company		Gas Rates			Operating Costs					Cost Control			Expansion Costs		
		Sales Margin Per Mcf	Sales Price Per Mcf	Trans-portation Margin Per Mcf	Utility Pretax Op. Income Per Meter	O&M Costs Per Meter	O&M Per 1000 Empl	O&M Per 1000 Mile	Gas Utility Employees Per 1000 Customers	O&M Cost Growth 1997	O&M Avg. Growth 92-97	1997 O&M as % of Margin	Capital Costs Per Mile Line Added	Capital Cost Per Meter Added	Meters Per Mile Added
		$	$	$	$	$	$	$	#	%	%	%	$ 10,000	$ 1,000	#
Small Distributors															
CASCADE NATURAL GAS	U	0.74	1.83	0.29	162	223	74	9	3.02	8.8	7.1	45.1	18.1	3.3	55
COLONIAL GAS		4.03	9.14	0.36	217	230	71	11	3.23	-2.8	-0.8	41.1	44.7	5.8	76
CONNECTICUT ENERGY		3.71	10.44	1.72	241	321	101	24	3.20	-2.4	1.8	42.2	83.8	49.6	17
CTG RESOURCES	U	3.23	8.87	NA	318	387	95	NA	4.06	-6.4	3.1	43.5	NA	49.2	NA
NORTH CAR. NAT GAS		1.37	3.41	0.82	186	162	48	10	3.39	10.2	7.5	34.8	41.2	4.2	97
NUI CORP		(0.26)	6.78	1.01	126	263	85	16	3.11	0.8	4.5	55.0	43.1	12.5	34
PENNSYLVANIA ENT.		1.12	3.95	NA	192	NA	52	18	5.55	29.8	10.8	52.9	22.9	5.1	45
PROVIDENCE ENERGY		3.56	8.62	1.01	123	290	87	20	3.35	-0.5	2.5	50.8	NMF	12.2	NMF
SOUTH JERSEY IND.		1.35	8.11	0.96	189	186	72	10	2.59	5.4	6.5	33.2	12.5	7.4	17
SEMCO ENERGY INC.	U #	1.60	5.20	0.62	111	150	69	7	2.19	-1.1	2.0	52.7	NMF	3.6	NMF
YANKEE ENERGY		3.40	8.04	2.48	239	358	NA	NA	NA	-0.0	4.1	45.7	NA	13.8	NA
Average		**2.17**	**6.76**	**1.03**	**191**	**257**	**75**	**14**	**3.37**	**3.8**	**4.5**	**45.2**	**38.0**	**15.2**	**49**
Median		**1.60**	**8.04**	**0.96**	**189**	**247**	**73**	**11**	**3.22**	**0.0**	**4.1**	**45.1**	**41.2**	**7.4**	**45**
Median of all Groups		**2.23**	**6.45**	**0.74**	**139**	**211**	**77**	**10**	**2.82**	**-1.8**	**2.9**	**47.2**	**25.4**	**5.3**	**39**
Large Distributors															
AGL RESOURCES		2.57	6.53	0.28	120	173	88	8	1.95	-0.2	4.3	48.5	10.2	3.9	26
ATMOS ENERGY		2.01	5.52	NA	68	188	69	6	2.72	16.1*	8.7	56.3	1.5	0.4	38
INDIANA ENERGY INC		1.64	4.27	NA	77	167	84	8	1.99	-5.4	2.9	38.3	29.7	6.0	50
LACLEDE GAS		2.45	6.05	0.74	111	178	52	7	3.41	6.1	4.3	49.0	64.9	13.2	49
NEW JERSEY RES.		(1.26)	7.14	2.83	204	212	101	7	2.11	14.3	8.1	42.4	8.5	4.2	20
NICOR INC		1.07	4.81	0.44	111	81	46	3	1.75	-2.5	2.9	30.8	7.7	5.0	15
NORTHWEST NAT GAS	#	2.84	4.77	0.50	196	170	58	7	2.92	-2.9	4.1	33.5	23.2	4.7	50
PEOPLES ENERGY		2.17	6.45	1.25	137	255	87	NA	2.94	-6.4	2.0	49.7	NA	374.1	NA
PIEDMONT NAT. GAS		2.13	6.63	0.86	150	226	75	7	3.02	4.3	6.5	40.3	10.4	3.2	33
PUB. SERVICE OF N C		2.23	5.19	0.98	181	200	56	9	3.60	10.8	7.1	42.2	5.6	3.6	16
SOUTHWEST GAS		3.94	6.23	0.44	87	175	82	NA	2.13	1.4	4.7	49.6	NA	2.8	NA
WASHINGTON GAS LIGHT	U	2.67	7.65	1.20	204	247	96	21	2.58	-10.8	2.3	45.0	36.7	5.3	69
Average		**2.04**	**5.94**	**0.95**	**137**	**189**	**75**	**8**	**2.59**	**2.1**	**4.8**	**43.8**	**19.8**	**35.5**	**37**
Median		**2.20**	**6.14**	**0.80**	**129**	**183**	**79**	**7**	**2.65**	**0.6**	**4.3**	**43.7**	**10.3**	**4.4**	**35**
Median of all Groups		**2.23**	**6.45**	**0.74**	**139**	**211**	**77**	**10**	**2.82**	**-1.8**	**2.9**	**47.2**	**25.4**	**5.3**	**39**

** = Averages not based on a full five years of activity due to restructurings or lack of available data, IB Note: Access QBLUE for current blue-sky status of Nasdaq stocks.*

NA = Information not available, Mcf = Thousand Cubic Feet, O&M = Operating & Maintenance Expenses, Empl = Number of utility employees.

= AG Edwards makes a market, U = AG Edwards has managed an offering of common or common equivalent securities within the last three years.

FIGURE 2 Fiscal 1997 Productivity Statistics

Company		Gas Rates			Operating Costs					Cost Control			Expansion Costs		
		Sales Margin Per Mcf	Sales Price Per Mcf	Transportation Margin Per Mcf	Utility Pretax Op. Income Per Meter	O&M Costs Per Meter	O&M Per 1000 Empl	O&M Per 1000 Mile	Gas Utility Employees Per 1000 Customers	O&M Cost Growth 1997	O&M Avg. Growth 92-97	1997 O&M as % of Margin	Capital Costs Per Mile Line Added	Capital Cost Per Meter Added	Meters Per Mile Added
		$	$	$	$	$	$	$	#	%	%	%	$ 10,000	$ 1,000	#
Integrated Utilities															
COLUMBIA ENERGY		2.45	6.88	0.55	110	217	106	14	2.05	-4.8	3.1*	57.5	25.4	5.3	48
CONSOLIDATED NAT GAS		2.53	6.78	0.94	150	210	58	12	3.60	-7.8	0.9	43.2	18.9	NMF	(76)
EQUITABLE RESOURCES		3.21	7.88	0.71	200	557	NA	NA	NA	0.7	0.7*	59.2	NA	103.4	NA
KN ENERGY		1.84	5.68	1.07	124	218	29	3	7.44	-8.5	0.0*	81.4	0.3	1.1	3
MCN ENERGY GROUP	U P	2.11	5.18	0.58	150	242	98	17	2.47	-3.9	0.1	45.6	56.3	14.1	40
NATIONAL FUEL GAS		3.27	7.93	0.83	169	256	74	13	3.45	-7.0	1.2*	40.4	NMF	NMF	NMF
ONEOK INC		2.52	5.69	NA	137	190	81	9	2.35	-2.5	1.7	47.9	39.4	15.7	25
QUESTAR		1.84	4.45	0.13	91	159	61	5	2.61	4.7	5.1	51.0	12.8	2.8	46
Average		2.47	6.31	0.69	141	256	73	11	3.42	-3.6	1.6	53.3	25.5	23.7	14
Median		2.49	6.23	0.71	143	217	74	12	2.61	-4.3	1.1	49.5	22.1	9.7	33
Median of all Groups		2.23	6.45	0.74	139	211	77	10	2.82	-1.8	2.9	47.2	25.4	5.3	39
Diversified Utilities															
BAY STATE GAS		2.81	7.10	NA	139	354	106	20	3.36	-0.6	5.7	50.2	84.8	9.9	86
CMS ENERGY CLASS 'G'		1.66	4.43	0.29	100	136	80	9	1.71	-10.3	-1.6	41.0	21.9	3.9	56
EASTERN ENTERPRISES		NA	NA	NA	148	319	118	29	2.70	-5.9	2.6	56.4	NA	6.2	NA
ENERGEN	U	3.58	7.93	0.50	85	210	65	11	3.21	4.0	6.6	52.0	28.9	9.0	32
KEYSPAN ENERGY		3.53	8.07	1.14	177	313	135	88	2.33	-4.8	1.2	62.3	265.6	43.9	61
MDU RESOURCES		1.35	4.47	NA	52	142	NA	NA	NA	-5.0	2.0	57.2	NA	2.6	31
SEMPRA ENERGY		3.60	7.03	0.67	102	147	108	16	1.37	-1.8	-7.6	45.8	47.6	4.0	120
SOUTHERN UNION		1.89	5.55	0.33	75	115	70	7	1.63	2.2	NA	47.2	37.0	21.8	17
UGI CORPORATION		NA	NA	NA	296	297	73	18	4.07	-2.0	-2.0	44.3	28.4	7.5	38
WICOR, INC.		1.99	5.95	NA	114	179	97	11	1.85	-7.0	NA	48.0	17.5	4.3	41
Average		2.55	6.32	0.59	129	221	95	23	2.47	-3.1	0.9	50.5	66.5	11.3	54
Median		2.40	6.49	0.50	108	195	97	16	2.33	-3.4	1.6	49.1	32.9	6.8	41
Median of all Groups		2.23	6.45	0.74	139	211	77	10	2.82	-1.8	2.9	47.2	25.4	5.3	39

** = Averages not based on a full five years of activity due to restructurings or lack of available data, IB Note: Access QBLUE for current blue-sky status of Nasdaq stocks.*

NA = Information not available, Mcf = Thousand Cubic Feet, O&M = Operating & Maintenance Expenses, Empl = Number of utility employees.

= AG Edwards makes a market, U = AG Edwards has managed an offering of common or common equivalent securities within the last three years.

P = Analyst holds a position in the shares.

(continued from page 1)

natural gas industry including exploration, production and transmission as well as distribution. In most cases, these companies have a market capitalization of at least $1 billion. And finally, the Diversified Utilities group is a mixed bag of gas utilities that have characteristics unlike those of the other three groups, including companies currently involved in merger transactions as well as those utilities with significant nongas-related operations.

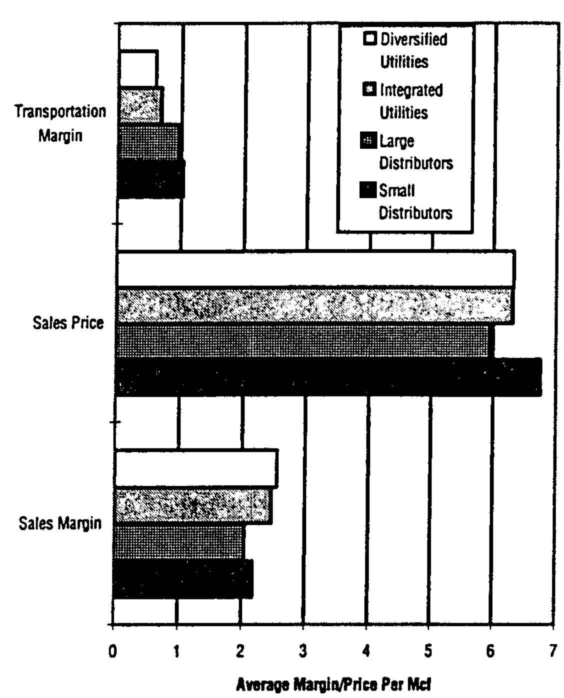
For this study, we have identified four categories of company performance in order to capture strategic competitive areas for gas utilities. The four categories include gas rates, operating costs, cost control and expansion costs. Within each category we used several different measures in order to provide an in-depth analysis of productivity and to avoid unduly weighting any one statistic. The data used in the study was gathered from a variety of sources, including direct company contact, company 10-Ks and annual reports. In addition, the preliminary results of the productivity study were sent to each company for verification. We attempted to single out only the information pertaining to the utility operations for all companies. It is important to note, however, that making any comparisons between individual companies based on these results can be difficult due to differences in geography, labor costs, customer class makeup and regulatory environments.

Gas Rates

The Gas Rates category provides an estimated average rate charged for gas service. The Sales Margin per Mcf (thousand cubic feet) figure is calculated by subtracting the total cost of gas from the total gas sales revenue and dividing by total sales throughput. Because the cost of gas is passed through directly to the customers, the sales margin figure is more representative of the rates charged for the delivery of the commodity. The Sales Price per Mcf does not subtract the cost of gas and represents the rate charged for the delivery service as well as the commodity itself. The Firm Transportation Margin per Mcf represents the rate charged to those customers who have secured their own gas supply and require only transportation of the gas on the utility's distribution system.

Gas rate data for 1997 continues to reflect the relative rate advantage of large utilities compared with smaller utilities. (See Figure 3.) Small distributors, lacking the operating efficiencies of the larger companies, usually suffer from higher operation and maintenance (O&M) costs and pass these costs onto customers in the form of higher rates. As we have mentioned in the past, the small utility group is likely impacted by the concentration of companies within that group that operate in the northeast. Companies in this part of the country typically face higher costs (labor, maintenance, etc.) relative to their peers. In the Transportation Margin category, the large diversified and integrated utilities have a relative rate advantage over smaller utilities, possibly due to many of these larger LDCs serving major cities with many large industrial customers that are able to negotiate lower rates. In addition, these companies have the opportunity to gain production efficiencies through their ability to spread out their overhead costs.

FIGURE 3 **Gas Rates**

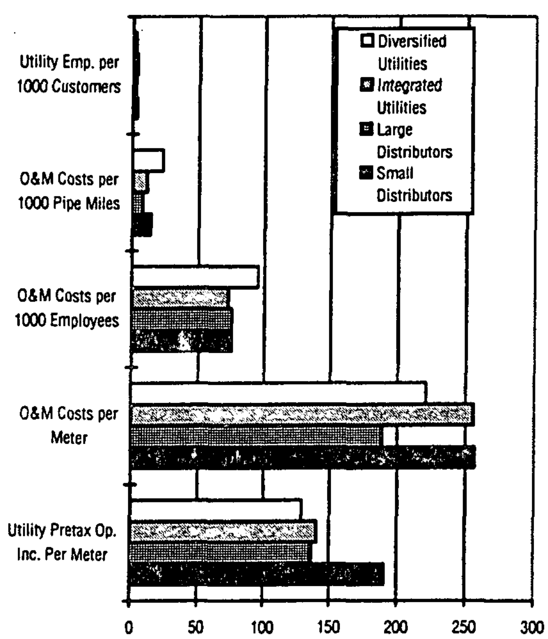


Operating Costs

The analysis of utility operating costs focuses on five different ratios. In addition to comparing operations and maintenance costs to three different measures of distribution system size (meters in service, employees and pipe miles), we looked at ratios of utility employees per 1,000 customers and utility pretax operating income per meter.

Small distributors continue to have higher per-meter operating costs than their larger counterparts. (See Figure 4.) Large utilities can gain cost advantages through economies of scale by spreading out corporate overhead and other fixed costs over a larger customer base. The concentration of small utilities in the northeast also contributes to the higher per meter O&M costs. The distribution systems in the northeast tend to be older and require more maintenance from a higher cost labor force. The higher pretax operating income per meter shown by the small group of distributors can likely be attributed to higher gas rates charged and the group's customer class profile. The small distributors have passed the higher O&M costs on to customers in the form of higher gas rates. They also tend to have a greater percentage of the higher margin residential customers compared with the other utility groups and, thus, a higher pretax operating income per customer.

FIGURE 4 **Operating Costs**



Cost Control

The Cost Control category measures the growth in utilities' operations & maintenance (O&M) costs. The growth in O&M expenses should be viewed in relationship to the companies' distribution system growth. High O&M cost growth by a utility company could reflect an expansion of the distribution operations. As a general rule, we like to see O&M expenses increase at a rate below utility customer growth. Other contributing factors to O&M cost growth include labor costs, age of equipment and the makeup of the distribution service territory. For the 1997 study, we have added a category to track O&M expenses as a percentage of sales margin. This figure provides additional perspective on the relative performance of a company's ability to control O&M costs.

The small distributors experienced the largest growth in O&M costs during 1997, however, the large distributors have shown the largest growth over the last five years. (See Figure 5.) The integrated and diversified groups continue to keep O&M costs in check and actually reduced O&M expense in 1997. This would support the argument that the natural gas industry is moving toward an integration of upstream and downstream functions and that those concentrating solely on distribution are at a disadvantage. However, while these results show the recent cost-cutting diligence of the integrated and diversified groups, the small and large pure distributors still show a lower O&M expense as a percentage of gross margin. (See Figure 6 on page 6.) Again, it is difficult to draw general conclusions regarding O&M expense management without looking at the specific service territory and customer growth levels.

FIGURE 5 **Cost Control**

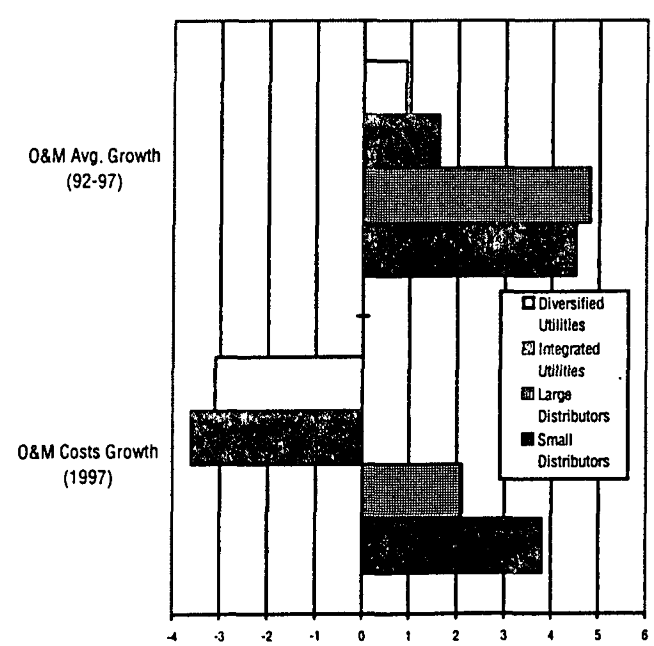


FIGURE 6 1997 O&M Expenses as a Percentage of Gross Margin

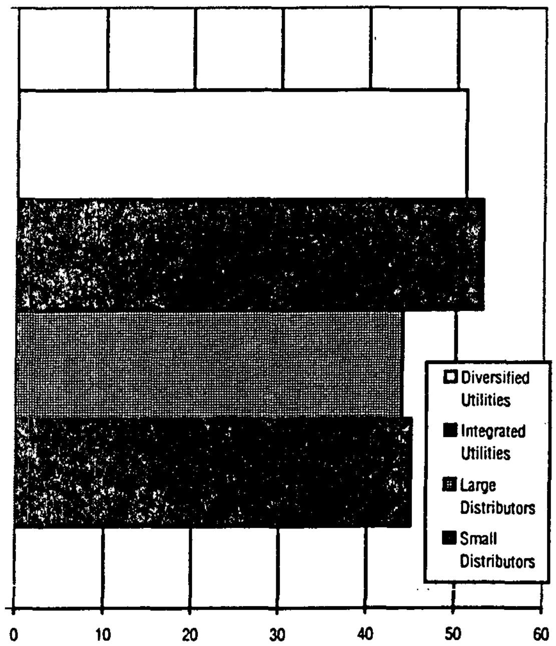
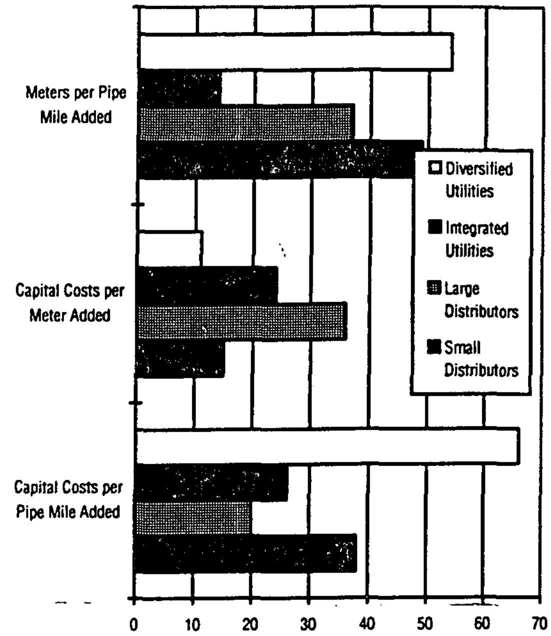


FIGURE 7 Expansion Costs



Expansion Costs

This category measures the cost and efficiency of distribution system expansion. The capital expenditures are analyzed based on the increase in pipe miles as well as the increase in meters served. Meters per pipe mile information is also calculated. The capital costs per meter added figure is an important measure because of its reflection on how the company's capital spending has created additional revenue.

The small distributors showed higher meters per pipe mile relative to the large distributors as well as lower capital costs per meter added. (See Figure 7.) These results are likely an indication of higher customer growth among some of the smaller gas utilities in our index. The higher capital costs per pipe mile added for the small distributors could once again be related to the northeastern location of many of the utilities in this group. In the northeast, much of the customer growth is derived from customer conversions to natural gas from alternative fuels, thus these utilities are able to add customers to an already existing main.

Comparing 1997 Results With 1996

During 1997, the overall O&M costs for the group were flat per meter, increased slightly per employees and declined 9.1% in the per-mile category. (See Figure 8.) Because O&M expenses for many of the gas utilities actually declined in 1997, the higher per employees figure is largely due to slower growth in the denominator. For example, many of the utilities have been aggressively reducing their number of utility employees in preparation for a more competitive environment. The sharp decline in gas utility employees per thousand customers also serves as evidence of this trend. The capital cost per pipe mile and meter added for the group also showed declines in 1997. Although some of this decline could be weather related, we have seen evidence that many gas utilities are becoming more cautious in their capital expenditure programs. The current regulatory trend of lower allowed returns and reluctant rate relief has led to more calculated plans for system expansion. Many utilities have stated they can no longer afford to offer service to certain nonprofitable customers due to the uncertainty of future rate relief.

FIGURE 8 **Productivity Statistics**

	Small Distributors			Large Distributors			Integrated Utilities			Diversified Utilities			Gas Utilities Group		
	Fiscal 1996 (median)	Fiscal 1997 (median)	% Change	Fiscal 1996 (median)	Fiscal 1997 (median)	% Change	Fiscal 1996 (median)	Fiscal 1997 (median)	% Change	Fiscal 1996 (median)	Fiscal 1997 (median)	% Change	Fiscal 1996 (median)	Fiscal 1997 (median)	% Change
O&M Costs per Meter ($)	239	247	3.3	185	183	-1.1	233	217	-6.9	189	195	3.2	211	211	-
O&M per 1000 Employees ($)	77	73	-5.2	76	79	3.9	68	74	8.8	84	97	15.5	75	77	2.7
O&M per 1000 Pipe Miles ($)	13	11	-15.4	8	7	-12.5	11	12	9.1	11	16	45.5	11	10	-9.1
Gas Utility Empl per 1000 Customers	3.4	3.2	-5.6	2.9	2.7	-9.9	3.7	2.6	-29.3	2.5	2.3	-4.9	3.1	2.8	-9.0
Capital Cost per Mile Line Added ($10,000)	35	41	17.1	29	10	-65.5	23	22	-4.3	20	33	65.0	29	25	-13.8
Capital Cost per Meter Added ($1,000)	10	7	-30.0	5	4	-12.0	7	10	38.6	5	7	36.0	6	5	-11.7

Conclusions

The data in the 1997 study continues to highlight the productivity advantages of large local distribution companies versus the small LDCs, though the gap seems to have narrowed compared with the 1996 study. Once again, it seems the smaller LDCs were faced with higher labor and operating costs which translated into higher gas rates charged from this group. Surprisingly, the integrated utilities showed a higher gas sales margin in 1997 compared with the small and large pure distributors. However, the results did reveal lower transportation margins achieved by the integrated utilities relative to the pure distributors. The operations and maintenance (O&M) expenses growth rate continues to decline for the industry as a whole. In fact, the integrated and diversified utilities actually reduced O&M expenses in 1997. We believe much of the operating cost reductions that have been achieved over the last few years from reducing utility employees and higher pension asset returns might be reaching a saturation point. As such, we anticipate O&M expenses for the industry will likely grow at a rate consistent with inflation going forward. Another interesting result from this year's study was the sharp decline in expansion costs. For example, the large distributor group experienced a 66% decline in capital cost per additional pipe mile over last year. We feel this serves as further evidence that many gas utilities have realized they can no longer depend on rate relief for expanding their distribution system. In response, many of the gas utilities have become more effective in controlling their expansion costs.

Current favorably rated stocks in the Large Distributor group that performed well include NICOR Inc. and Northwest Natural Gas. In the Integrated and Diversified categories, Questar and CMS Energy Class G were among those with favorable productivity results relative to their peers. We should note that these productivity results are only one of many factors to consider when evaluating these gas utility stocks. Some companies operate in saturated markets where expansion comes only through building lines to new subdivisions which is more expensive than converting customers to gas. Some companies serve older cities with older pipes requiring higher cost maintenance. Construction and maintenance is also more expensive for those companies serving the areas with a colder climate. The state regulatory environments in which these companies operate can differ significantly and each company has its own unique management style and strategic direction. We do feel, however, that these productivity measures can be a useful tool in monitoring how well these companies have positioned themselves to operate in the increasingly competitive gas utility industry.

A.G. Edwards

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 63 a through c
Witness: Conrad E. Gruber

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 1, the Testimony of Conrad E. Gruber, specifically page 16, which indicates that installation of the Oracle system was expected to be completed by July 1999, and refers to the series of IT projects that are essential for Y2K readiness.

a. Has the Oracle system been implemented and tested for Y2K readiness?

Response:
Yes.

b. Provide a description of the other projects scheduled for completion prior to the end of 1999 to assure Western's customers of Y2K readiness.

Response:
All hardware and software is, or will be Y2K ready by August 1, 1999. The only exception being the MV-90 system that supports large volume customer nominations. The MV-90 system does not affect gas supply. The MV-90 system will be implemented, tested and, Y2K ready by September 1, 1999.

c. Identify any costs associated with Western's Y2K readiness that are included in the base year or the forecasted year.

Response:
Western's total cost for the Y2K effort in the base year is $167,000. Costs incurred as of August 27, 1999 are $69,871. Western does not anticipate any Y2K costs in the forecasted year.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 64
Witness: Donald P. Burman

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 6, the Testimony of Donald P. Burman, and Volume 4 of 10, Tab 4, Filing Requirement 10(9)(m).

a. Explain whether FR 10(9)(m) is a complete conversion table to NARUC accounts as presented for operating revenue and expenses in Volume 10 of 10, FR 10(10)(c), Schedule C-2.1 and Schedule C-2.2.

b. Are the references in the "detail" sections of this exhibit to NARUC accounts the same as the accounts used to file the annual FERC Form No. 2 with the Commission?

Response:

a. Rather than being a conversion table, FR 10(9)(m) is a detailed listing of the Company's NARUC chart of accounts.

b. The "detail" sections of this exhibit are simply internal subdivisions of the individual NARUC account numbers.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 65
Witness: Betty L. Adams

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 4, the Testimony of Betty L. Adams. Does Western have a conversion table that converts its current chart of accounts for general ledger purposes to the NARUC accounts as presented for operating revenue and expenses in Volume 10, FR 10(10)(c), Schedule C-2.1 and Schedule C-2.2? If yes, provide the conversion table.

Response:

Yes, please see attached Chart of Accounts, Comparison of FERC and NARUC

CHART OF ACCOUNTS
COMPARISON OF FERC AND NARUC FERC.WK1

NARUC	FERC	DESCRIPTION
ASSETS & OTHER DEBITS		
Utility Plant		
101	101	Gas plant in service
N/A	101.1	Property under capital leases
102	102	Gas plant purchased or sold
N/A	103	Experimental gas plant unclassified (Major only)
103	103.1	Gas plant in process of reclassification (Nonmajor only)
104	104	Gas plant leased to others
105	105	Gas plant held for future use
105.1	105.1	Production properties held for future use (Major only)
106	106	Completed construction not classified - Gas (Major only)
107	107	Construction work in progress - Gas
108	108	Accumulated provisions for depreciation of gas utility plant (Major only)
N/A	109	[Reserved]
N/A	110	Accumulated provision for depreciation, depletion, and amortization of gas utility plant (Nonmajor only)
N/A	111	Accumulated provision for amortization and depletion of gas utility plant (Major only)
N/A	111.1-111.2	[Reserved]
N/A	112	[Reserved]
N/A	113.1-113.2	[Reserved]
N/A	114	Gas plant acquisition adjustments
N/A	115	Accumulated provision for amortization of gas plant acquisition adjustments
116	116	Other gas plant adjustments
117	117	Gas stored underground - Noncurrent (Major only)
N/A	118	Other utility plant
111.3	119	Accumulated provision for depreciation and amortization of other utility plant
Other Property and Investments		
121	121	Nonutility property
122	122	Accumulated provision for depreciation and amortization of nonutility property
123	123	Investment in associated companies (Major only)
N/A	123.1	Investment in subsidiary companies (Major only)
124	124	Other investments
125	125	Sinking funds (Major only)
126	126	Depreciation fund (Major only)
128	128	Other special funds (Major only)
N/A	129	Special funds (NonMajor only)
Current and Accrued Assets		
N/A	130	Cash and working funds (Nonmajor only)
131	131	Cash (Major only)
132	132	Interest special deposits (Major only)
133	133	Dividend special deposites (Major only)
134	134	Other special deposits (Major only)
135	135	Working funds (Major only)
136	136	Temporary cash investments
141	141	Notes receivable
142	142	Customer accounts receivable
143	143	Other accounts receivable
144	144	Accumulated provision for uncollectible accounts-Cr
145	145	Notes receivable from associated companies
146	146	Accounts receivable from associated companies
151	151	Fuel stock (Major only)
152	152	Fuel stock expenses undistributed (Major only)
153	153	Residuals and extracted products (Major only)
154	154	Plant materials and operating supplies (Major only)

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC FERC.WK1

NARUC	FERC	DESCRIPTION
155	155	Merchandise (Major only)
156	156	Other materials and supplies (Major only)
163	163	Stores expense undistributed (Major only)
164	164.1	Gas stored underground - current
165	164.2	Liquefied natural gas stored
N/A	164.3	Liquefied natural gas held for processing (Major only)
166	165	Prepayments
167	166	Advances for gas exploration, development, and production (Major only)
168	167	Other advances for gas (Major only)
171	171	Interest and dividends receivable (Major only)
172	172	Rents receivable (Major only)
173	173	Accrued utility revenues (Major only)
174	174	Miscellaneous current and accrued assets
Deferred Debits		
181	181	Unamortized debt expense
182	182.1	Extraordinary property losses
N/A	182.2	Unrecovered plant and regulatory study costs
183.1	183.1	Preliminary natural gas survey and investigation charges (Major only) (Major only)
183.2	183.2	Other preliminary survey and investigation charges (Major only) (Major only)
184	184	Clearing accounts (Major only)
185	185	Temporary facilities (Major only)
186	186	Miscellaneous deferred debits
N/A	187	Deferred losses from disposition of utility plant
187	188	Research, development and demonstration expenditures (Major only)
N/A	189	Unamortized loss on reacquired debt
N/A	190	Accumulated deferred income taxes
N/A	191	Unrecovered purchased gas costs
N/A	192.1	Unrecovered incremental gas costs
N/A	192.2	Unrecovered incremental gas surcharges
LIABILITIES AND OTHER CREDITS		
Proprietary Capital		
201	201	Common stock issued
202	202	Common stock subscribed (Major only)
203	203	Common stock liability for conversion (Major only)
204	204	Preferred stock issued
205	205	Preferred stock subscribed (Major only)
206	206	Preferred stock liability for conversion (Major only)
207	207	Premium on capital stock (Major only)
208	208	Donations received from stockholders (Major only)
209	209	Reduction in par or stated value of capital stock (Major only)
210	210	Gain on resale or cancellation or reacquired capital stock (Major only)
211	211	Miscellaneous paid-in capital
212	212	Installments received on capital stock
213	213	Discount on capital stock
214	214	Capital stock expense
215	215	Appropriated retained earnings
216	216	Unappropriated retained earnings
N/A	216.1	Unappropriated undistributed subsidiary earnings (Major only)
217	217	Reacquired capital stock
N/A	218	Noncorporate proprietorship (Nonmajor only)
Long-Term Debt		
221	221	Bonds
222	222	Reacquired bonds (Major only)
223	223	Advances from associated companies

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
224	224	Other long-term debt
N/A	225	**Unamortized premium on long-term debt**
N/A	226	**Unamortized discount on long-term debt-Debit**
Other Noncurrent Liabilities		
N/A	227	**Obligations under capital leases-non-current**
261	228.1	**Accumulated provision for property insurance**
262	228.2	**Accumulated provision for injuries and damages**
263	228.3	**Accumulated provision for pensions and benefits**
265	228.4	**Accumulated miscellaneous operating provisions**
N/A	229	**Accumulated provision for rate refunds**
Current and Accrued Liabilities		
231	231	Notes payable
232	232	Accounts payable
233	233	Notes payable to associated companies
234	234	Accounts payable to associate companies
235	235	Customer deposits
236	236	Taxes accrued
237	237	Interest accrued
238	238	Dividends declared (Major only)
239	239	Matured long-term debit (Major only)
240	240	Matured interest (Major only)
241	241	Tax collections payable (Major only)
242	242	Miscellaneous current and accrued liabilities
N/A	243	**Obligations under capital leases-current**
...rred Credits		
251	N/A	**Unamortized Premium on Debt**
252	252	Customer advances for construction
253	253	Other deferred credits
255	255	Accumulated deferred investment tax credits
N/A	256	**Deferred gains from disposition of utility plant**
N/A	257	**Unamortized gain on reacquired debt**
271		**Contributions in Aid of Construction**
281	281	Accumulated deferred income taxes-Accelerated amortization property
282	282	Accumulated deferred income taxes-Other property
283	283	Accumulated deferred income taxes-Other

GAS PLANT ACCOUNTS

Intangible Plant

NARUC	FERC	
301	301	Organization
302	302	Franchises and Consents
303	303	Miscellaneous Intangible Plant
Production Plant		
A. Manufactured Gas Production Plant		
304	304	Land and Land Rights
305	305	Structures and Improvements
306	306	Boiler Plant Equipment
307	307	Other Power Equipment
308	308	Coke Ovens
309	**308**	**Producer Gas Equipment**
310	310	Water Gas Generating Equipment
311	311	Liquefied Petroleum Gas Equipment
312	312	Oil Gas Generating Equipment
313	313	Generating Equipment - Other Processes

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
314	314	Coal. Coke and Ash Handling Equipment
315	315	Catalytic Cracking Equipment
316	316	Other Reforming
317	317	Purification Equipment
318	318	Residual Refining Equipment
319	319	Gas Mixing Equipment
320	320	Other Equipment
B. Natural Gas Production Plant		
b.1 Natural Gas Production and Gathering Plant		
325.1	325.1	Producing Lands
325.2	325.2	Producing Leaseholds
325.3	325.3	Gas Rights
325.4	325.4	Rights-of-Way
325.5	325.5	Other Land and Land Rights
326	326	Gas Well Structures
327	327	Field Compressor Station Structures
328	328	Field Measuring and Regulating Station Structures
329	329	Other Structures
330	330	Producing Gas Wells - Well Construction
331	331	Producing Gas Wells - Well Equipment
332	332	Field Lines
333	333	Field Compressor Station Equipment
334	334	Field Measuring and Regulating Station Equipment
335	335	Drilling and Cleaning Equipment
336	336	Purification Equipment
337	337	Other Equipment
338	338	Unsuccessful Exploration and Development Costs
b.2 Products Extraction Plant		
340	340	Land and Land Rights
341	341	Structures and Improvements
342	342	Extraction and Refining Equipment
343	343	Pipe Lines Equipment
344	344	Extracted Products Storage Equipment
345	345	Compressor Equipment
346	346	Gas Measuring and Regulating Equipment
347	347	Other Equipment
Natural Gas Storage Plant		
A. Underground Storage Plant		
350.1	350.1	Land
350.2	350.2	Rights-of-Way
351	351	Structures and Improvements
352	352	Wells
352.1	352.1	Storage Leaseholds and Rights
352.2	352.2	Reservoirs
352.3	352.3	Nonrecoverable Natural Gas
353	353	Lines
354	354	Compressor Station Equipment
355	355	Measuring and Regulation Equipment
356	356	Purification Equipment
357	357	Other Equipment
B. Other Storage Plant		
360	360	Land and Land Rights
361	361	Structures and Improvements
362	362	Gas Holders
363	363	Purification Equipment

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC — FERC.WK1

NARUC	FERC	DESCRIPTION
363.1	363.1	Liquefaction Equipment
363.2	363.2	Vaporizing Equipment
363.3	363.3	Compressor Equipment
363.4	363.4	Measuring and Regulation Equipment
363.5	363.5	Other Equipment
Tranmission Plant		
N/A	**364.1**	**Land and land rights (Major only)**
N/A	**364.2**	**Structures and improvements (Major only)**
N/A	**364.3**	**LNG processing terminal equipment (Major only)**
N/A	**364.4**	**LNG transportation equipment (Major only)**
N/A	**364.5**	**Measuring and regulating equipment (Major only)**
N/A	**364.6**	**Compressor station equipment (Major only)**
N/A	**364.7**	**Communication equipment (Major only)**
N/A	**364.8**	**Other equipment (Major only)**
Transmission Plant		
365.1	365.1	Land and Land Rights
N/A	**365.2**	**Rights-of-way**
365.2	**366**	**Structures and Improvements**
366	**367**	**Mains**
367	**368**	**Compressor Station Equipment**
368	**368**	**Measuring and Regulating Station Equipment – General**
369	**N/A**	**Measuring and Regulating Station Equipment – City Gate Check Stations**
370	370	Communication Equipment
371	371	Other Equipment
Distribution Plant		
374	374	Land and Land Rights
375	375	Structures and Improvements
376	376	Mains
377	377	Compressor Station Equipment
378	378	Measuring and Regulating Station Equipment – General
379	379	Measuring and Regulating Station Equipment – City Gate Check Stations
380	380	Services
381	381	Meters
382	382	Meter Installations
383	383	House Regulators
384	384	House Regulator Installations
385	385	Industrial Measuring and Regulating Station Equipment
386	386	Other Property on Customers' Premises
387	387	Other Equipment
General Plant		
389	389	Land and Land Rights
390	390	Structures and Improvements
391	391	Office Furniture and Equipment
392	395	Transportation Equipment
393	393	Stores Equipment
394	384	Tools, Shop and Garage Equipment
395	395	Laboratory Equipment
396	396	Power Operated Equipment
397	397	Communication Equipment
398	398	Miscellaneous Equipment
399	399	Other Tangible Property

INCOME ACCOUNTS

Utility Operating Income

400	400	Operating Revenues

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
rating Expenses		
401	401	Operation Expense
402	402	Maintenance Expense
403	403	Depreciation Expense
N/A	403.1	**Depreciation and depletion expense**
N/A	404	**Amortization of limited-term gas plant (Nonmajor only)**
404.1	404.1	Amortization and Depletion of Producing Natural Gas Land and Land Rights
404.2	404.2	Amortization of Underground Storage Land and Land Rights
404.3	404.3	Amortization of Other Limited-Term Utility Plant
405	405	Amortization of Other Utility Plant
406	406	Amortization of Utility Plant Acquisition Adjustments
407.1	407.1	Amortization of Property Losses
407.2	407.2	Amortization of Conversion Expenses
N/A	408	**[Reserved]**
408.1	408.1	Taxes Other than Income Taxes, Utility Operating Income
N/A	409	**[Reserved]**
409.1	409.1	Income Taxes, Utility Operating Income
N/A	410	**[Reserved]**
410.1	410.1	Provision for Deferred Income Taxes, Utility Operating Income
N/A	411	**[Reserved]**
411.1	411.1	Income Taxes Deferred in Prior Years - Credit, Utility Operating Income
N/A	411.3	**[Reserved]**
N/A	411.4	**Investment tax credit adjustments, utility operations**
N/A	411.6	**Gains from disposition of utility plant**
N/A	411.7	**Losses from disposition of utility plant**
412.1	N/A	**Investment Tax Credits, Utility Operations, Deferred to Future Periods**
412.2	N/A	**Investment Tax Credits, Utility Operations, Restored to Operating Income**
Other Operating Income:		
413	412	**Income from Utility Plant Leased to Others**
N/A	413	**Expenses of gas plant leased to others**
N/A	414	**Other utility operating income**
414	N/A	**Gains (Losses) from Disposition of Utility Property**
Other Income and Deductions		
A. Other Income		
415	415	Revenues from Merchandising, Jobbing and Contract Work
416	416	Costs and Expense of Merchandising, Jobbing and Contract Work
417	N/A	**Income from Nonutility Operations**
N/A	417	**Revenues from nonutility operations**
N/A	417.1	**Expenses of nonutility operations**
418	418	Nonoperating Rental Income
N/A	418.1	**Equity in earnings of subsidiary companies**
419	419	Interest and Dividend Income
420	419.1	**Allowance for Funds Used During Construction**
421	421	Miscellaneous Nonoperating Income
422	421.1	**Gains (Losses) from Disposition of Property**
422	421.2	**Gains (Losses) from Disposition of Property**
B. Other Income Deductions		
425	425	Miscellaneous Amortization
426	N/A	**Miscellaneous Income Deductions**
N/A	426	**[Reserved]**
N/A	426.1	**Donations**
N/A	426.2	**Life insurance**
N/A	426.3	**Penalties**
N/A	426.4	**Expenditures for certain civic, political and related activities**

COMPARISON OF FERC AND NARUC

NARUC	FERC	DESCRIPTION
N/A	426.5	Other deductions
C. Taxes Applicable to Other Income and Deductions		
408.2	408.2	Taxes Other than Income Taxes, Other Income and Deductions
409.2	409.2	Income Taxes, Other Income and Deductions
410.2	410.2	Provision for Deferred Income Taxes, Other Income and Deductions
411.2	411.2	Income Taxes Deferred in Prior Years - Credit, Other Income and Deductions
412.3	N/A	Investment Tax Credits, Utility Operations, Restored to Nonoperating Income.
N/A	411.5	Investment tax credit adjustments, nonutility operations.
412.4	420	Investment Tax Credits, Nonutility Operations, Net Total Taxes on Other Income and Deductions
Interest Charges		
427	427	Interest on Long-Term Debt
428	428	Amortization of Debt Discount and Expense
N/A	428.1	Amortization of loss on reacquired debt
429	429	Amortization of Premium on Debt - Cr.
430	430	Interest on Debt to Associated Companies
431	431	Other Interest Expense
N/A	432	Allowance for borrowed funds used during construction - credit.
Extraordinary Items		
433	434	Extraordinary Income
434	435	Extraordinary Deductions
409.3	409.3	Income Taxes, Extraordinary Items
RETAINED EARNINGS ACCOUNTS		
216	216	Unappropriated Retained Earnings (at beginning of period)
435	433	Balance Transferred from Income
436	436	Appropriations of Retained Earnings
437	437	Dividends Declared - Preferred Stock
438	438	Dividends Declared - Common Stock
439	439	Adjustments to Retained Earnings
216	216	Unappropriated Retained Earnings (at end of period)
OPERATING REVENUE ACCOUNTS		
Sales of Gas		
480	480	Residential Sales
481	481	Commerical and Industrial Sales
482	482	Other Sales to Public Authorities
483	483	Sales for Resale
484	484	Interdepartmental Sales
N/A	485	Intracompany transfers
Other Operating Revenues		
487	487	Forfeited Discounts
488	488	Miscellaneous Service Revenues
489	489	Revenues from Transportation of Gas of Others
490	490	Sales of Products Extracted from Natural Gas
491	491	Revenues from Natural Gas Processed by Others
492	492	Incidental Gasoline and Oil Sales
493	493	Rent from Gas Property
494	494	Interdepartmental Rents
495	495	Other Gas Revenues
N/A	496	Provision for rate refunds
OPERATION AND MAINTENANCE EXPENSE ACCOUNTS		
...ction Expenses		
A. Manufactured Gas Production Expenses		
A.1 Steam Production		
Operation		
700	700	Operation Supervision and Engineering
701	701	Operating Labor

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC FERC.WK1

NARUC	FERC	DESCRIPTION
702	702	Boiler Fuel
703	703	Miscellaneous Steam Expenses
704	704	Steam Transferred - Cr.
Maintenance		
705	705	Maintenance Supervision and Engineering
706	706	Maintenance of Structures and Improvements
707	707	Maintenance of Boiler Plant Equipment
708	708	Maintenance of Other Steam Production Plant
A.2 Manufactured Gas Production		
Operation		
Production Labor and Expenses		
710	710	Operation Supervision and Engineering
711	711	Steam Expenses
712	712	Other Power Expenses
713	713	Coke Oven Expenses
714	714	Producer Gas Expenses
715	715	Water Gas Generating Expenses
716	716	Oil Gas Generating Expenses
717	717	Liquefield Petroleum Gas Expenses
718	718	Other Process Production Expenses
Gas Fuels		
719	719	Fuel Under Coke Ovens
720	720	Producer Gas Fuel
721	721	Water Gas Generator Fuel
722	722	Fuel for Oil Gas
723	723	Fuel for Liquefied Petroleum Gas Process
724	724	Other Gas Fuels
N/A	**724.1**	**Fuel**
Gas Raw Materials		
725	725	Coal Carbonized in Coke Ovens
726	726	Oil for Water Gas
727	727	Oil for Oil Gas
728	728	Liquefied Petroleum Gas
729	729	Raw Materials for Other Gas Processes
730	730	Residuals Expenses
731	731	Residuals Produced - Credit
732	732	Purification Expenses
733	733	Gas Mixing Expenses
734	734	Duplicate Charges - Credit
735	735	Miscellaneous Production Expenses
736	736	Rents
N/A	**737**	**Operation supplies and expenses**
Maintenance		
740	740	Maintenance Supervision and Engineering
741	741	Maintenance of Structures and Improvements
742	742	Maintenance of Production Equipment
N/A	**743**	**Maintenance of Production Plant**
B. Natural Gas Production Expenses		
Natural Gas Production and Gathering		
Operation		
750	750	Operation Supervision and Engineering
751	751	Production Maps and Records
752	752	Gas Wells Expenses
753	753	Field Lines Expenses
754	754	Field Compressor Station Expenses

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
755	755	Field Compressor Station Fuel and Power
756	756	Field Measuring and Regulating Station Expenses
757	757	Purification Expenses
758	758	Gas Wells Royalties
759	759	Other Expenses
760	760	Rents
Maintenance		
761	761	Maintenance Supervision and Engineering
762	762	Maintenance of Structures and Improvements
763	763	Maintenance of Producing Gas Wells
764	764	Maintenance of Field Lines
765	765	Maintenance of Field Compressor Station Equipment
766	766	Maintenance of Field Measuring and Regulating Station Equipment
767	767	Maintenance of Purification Equipment
768	768	Maintenance of Drilling and Cleaning Equipment
769	769	Maintenance of Other Equipment
N/A	**769.1**	**Maintenance of Other Plant**
B.2 Products Extraction		
Operation		
770	770	Operation Supervision and Engineering
771	771	Operation Labor
772	772	Gas Shrinkage
773	773	Fuel
774	774	Power
775	775	Materials
776	776	Operation Supplies and Expenses
777	777	Gas Processed by Others
778	778	Royalties on Products Extracted
779	779	Marketing Expenses
780	780	Products Purchased for Resale
781	781	Variation in Products Inventory
782	782	Extracted Products Used by the Utility-Credit
783	783	Rents
Maintenance		
784	784	Maintenance Supervision and Engineering
785	785	Maintenance of Structures and Improvements
786	786	Maintenance of Extraction and Refining Equipment
787	787	Maintenance of Pipe Lines
788	788	Maintenance of Extracted Products Storage Equipment
789	789	Maintenance of Compressor Equipment
790	790	Maintenance of Gas Measuring and Regulating Equipment
791	791	Maintenance of Other Equipment
N/A	**792**	**Maintenance of products extraction**
C. Exploration and Development Expenses		
Operation		
795	795	Delay Rentals
796	496	Nonproductive Well Drilling
797	797	Abandoned Leases
798	798	Other Exploration
Other Gas Supply Expenses		
Operation		
N/A	**799**	**Natural Gas Purchases**
800	800	Natural Gas Well Head Purchases
N/A	**800.1**	**Natural Gas Well Head Purchases, intracompany transfers**
801	801	Natural Gas Field Line Purchases

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
802	802	Natural Gas Gasoline Plant Outlet Purchases
803	803	Natural Gas Transmission Line Purchases
804	804	Natural Gas City Gate Purchases
N/A	804.1	**Liquefied Natural Gas Purchases**
805	805	Other Gas Purchases
N/A	805.1	**Purchased Gas Cost Adjustments**
N/A	805.2	**Incremental Gas Cost Adjustments**
806	806	Exchange Gas
807	807	Purchased Gas Expenses
808	808.1	**Gas Withdrawn from Storage - Debit**
809	808.2	**Gas Delivered to Storage - Credit**
N/A	809.1	**Withdrawals of liquefied natural gas held for processing**
N/A	809.2	**Deliveries of natural gas for processing**
810	810	Gas Used for Compressor Station Fuel - Credit
811	811	Gas Used for Products Extraction - Credit
812	812	Gas Used for Other Utility Operations - Credit
N/A	812.1	**Gas Used in Utility Operations - Credit**
813	813	Other Gas Supply Expenses
Natural Gas Storage Expenses		
A. Underground Storage Expenses		
Operation		
814	814	Operation Supervision and Engineering
815	815	Maps and Records
816	816	Well Expenses
817	817	Lines Expenses
818	818	Compressor Station Expenses
819	819	Compressor Station Fuel and Power
820	820	Measuring and Regulating Station Expenses
821	821	Purification Expenses
822	822	Exploration and Development
823	823	Gas Losses
824	824	Other Expenses
825	825	Storage Wells Royalties
826	826	Rents
N/A	827	**Operating supplies and expenses**
Maintenance		
830	830	Maintenance Supervision and Engineering
831	831	Maintenance of Structures and Improvements
832	832	Maintenance of Reservoirs and Wells
833	833	Maintenance of Lines
834	834	Maintenance of Compressor Station Equipment
835	835	Maintenance of Measuring and Regulation Station Equipment
836	836	Maintenance of Purification Equipment
837	837	Maintenance of Other Equipment
N/A	838	**Maintenance of Other Underground Storage Plant**
N/A	839	**Maintenance of Locatl Storage Plant**
B. Other Storage Expenses		
Operation		
840	840	Operation Supervision and Engineering
841	841	Operation Labor and Expenses
842	842	Rents
842.1	842.1	Fuel
842.2	842.2	Power
842.3	842.3	Gas Losses
Maintenance		

CHART OF ACCOUNTS
COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
843	843.1	Maintenance Supervision
844	843.2	Maintenance of Structures and Improvements
845	843.3	Maintenance of Gas Holders
846	843.4	Maintenance of Purification Equipment
847	843.5	Maintenance of Liquefaction Equipment
848	843.6	Maintenance of Vaporizing Equipment
848.1	843.7	Maintenance of Compressor Equipment
848.2	843.8	Maintenance of Measuring and Regulating Equipment
848.3	843.9	Maintenance of Other Equipment
Liquefied Natural Gas Terminaling and Processing Expenses		
Operation		
N/A	844.1	Operation supervision and engineering
N/A	844.2	LNG processing terminal labor and expense
N/A	844.3	Liquefaction processing labor and expenses
N/A	844.4	LNG transportation labor and expenses
N/A	844.5	Measuring and regulating labor and expenses
N/A	844.6	Compressor station labor and expenses
N/A	844.7	Communication system expenses
N/A	844.8	System control and load dispatching
N/A	845.1	Fuel
N/A	845.2	Power
N/A	845.3	Rents
N/A	845.4	Demurrage charges
N/A	845.5	Wharfage receipts – credit
N/A	845.6	Processing liquefied or vaporized gas by others
N/A	846.1	Gas losses
N/A	846.2	Other expenses
Maintenance		
N/A	847.1	Maintenance supervision and engineering
N/A	847.2	Maintenance of structures and improvements
N/A	847.3	Maintenance of LNG processing terminal equipment
N/A	847.4	Maintenance of LNG transportation equipment
N/A	847.5	Maintenance of measuring and regulating equipment
N/A	847.6	Maintenance of compressor station equipment
N/A	847.7	Maintenance of communication equipment
N/A	847.8	Maintenance of other equipment
Transmission Expenses		
Operation		
850	850	Operation Supervision and Engineering
851	851	System Control and Load Dispatching
852	852	Communications System Expenses
853	853	Compressor Station Labor and Expenses
N/A	853.1	Compressor Station Fuel and Power
854	854	Gas for Compressor Station Fuel
855	855	Other Fuel and Power for Compressor Stations
856	856	Mains Expenses
857	857	Measuring and Regulating Station Expenses
N/A	857.1	Operation Supplies and Expenses
858	858	Transmission and Compression of Gas by Others
859	859	Other Expenses
860	860	Rents
Maintenance		
861	861	Maintenance Supervision and Engineering
862	862	Maintenance of Structures and Improvements
863	863	Maintenance of Mains

CHART OF ACCOUNTS

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
864	864	Maintenance of Compressor Station Equipment
865	865	Maintenance of Measuring and Regulation Station Equipment
866	866	Maintenance of Communication Equipment
867	867	Maintenance of Other Equipment
N/A	868	**Maintenance of Other Plant**
Distribution Expenses		
Operation		
870	870	Operation Supervision and Engineering
871	871	Distribution Load Dispatching
872	872	Compressor Station Labor and Expenses
873	873	Compressor Station Fuel and Power
874	874	Mains and Services Expenses
875	875	Measuring and Regulation Station Expenses - General
876	876	Measuring and Regulation Station Expenses - Industrial
877	877	Measuring and Regulation Station Expenses - City Gate Check Stations
878	878	Meter and House Regulator Expenses
879	879	Customer Installations Expenses
880	880	Other Expenses
N/A	880.1	**Miscellaneous distribution expenses**
881	881	Rents
Maintenance		
885	885	Maintenance Supervision and Engineering
886	886	Maintenance of Structures and Improvements
887	887	Maintenance of Mains
888	888	Maintenance of Compressor Station Equipment
889	889	Maintenance of Measuring and Regulation Station Expenses - General
890	890	Maintenance of Measuring and Regulation Station Expenses - Industrial
891	891	Maintenance of Measuring and Regulation Station Expenses - City Gate Check Stations
892	892	Maintenance of Services
N/A	892.1	**Maintenance of Lines**
893	893	Maintenance of Meters and House Regulators
894	894	Maintenance of Other Equipment
N/A	895	Maintenance of Other Plant
Customer Accounts Expenses		
Operation		
901	901	Supervision
902	902	Meter Reading Expenses
903	903	Customer Records and Collection Expenses
904	904	Uncollectible Accounts
905	905	Miscellaneous Customer Accounts Expenses
Customer Service Expenses		
Operation		
N/A	906	**Customer Service and Informational Expenses**
909	907	**Supervision**
910	908	**Customer Assistance Expenses**
911	909	**Informational Advertising Expenses**
912	910	**Miscellaneous Customer Service Expenses**
Sales Promotion Expenses		
Operation		
915	911	**Supervision**
916	912	**Demonstrating and Selling Expenses**
917	913	**Promotional Advertising Expenses**
N/A	914	**[Reserved]**
N/A	915	**[Reserved]**
918	916	**Miscellaneous Sales Promotion Expenses**

COMPARISON OF FERC AND NARUC

FERC.WK1

NARUC	FERC	DESCRIPTION
N/A	917	Sales expenses
Administrative and General Expenses		
Operation		
920	920	Administrative and General Salaries
921	921	Office Supplies and Expenses
922	922	Administrative Expenses Transferred - Credit
923	923	Outside Services Employed
924	924	Property Insurance
925	925	Injuries and Damages
926	926	Employee Pensions and Benefits
927	927	Franchise Requirements
928	928	Regulatory Commission Expenses
929	929	Duplicate Charges - Cr.
N/A	930.1	General advertising expenses
930.1	N/A	Institutional or Goodwill Advertising Expenses
930.2	930.2	Miscellaneous General Expense
931	931	Rents
Maintenance		
N/A	933	Transportation Expenses
932	935	Maintenance of General Plant

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 66
Witness: Betty L. Adams

Data Request:

Are the NARUC account numbers referenced in Ms. Adams testimony at page 5, lines 5 through 23, the same as the account numbers used to determine the account balances for the annual FERC Form No. 2 filed with the Commission? If no, is there a conversion table that converts from NARUC accounts, to FERC accounts, to Western's general ledger chart of accounts?

Response:

No. See DR 65 referencing chart of accounts conversion.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 67
Witness: Betty L. Adams

Data Request:

Refer to Ms. Adams' testimony.

a. Are the operating revenue and expenses in Volume 10, FR 10(10)(c), Schedule C-2.1 and Schedule C-2.2 according to NARUC accounts available according to Western's current general ledger chart of accounts? Resubmit these schedules according to the current chart of accounts.
b. Does Western have operating revenue and expenses in the detailed manner described above according to its current chart of accounts which compare budgeted amounts to actual year-to-date totals for the FY 1998, 1997, 1996, 1995 and 1994?
c. If yes to part (a) provide the budget to actual comparison for those years. Provide a brief explanation for accounts with a budget to actual variance of 5 percent or greater.
d. Resubmit Volume 10 FR 10(10)(d), the summary of jurisdictional adjustments, according to Western's general ledger chart of accounts.
e. Resubmit Volume 9, FR 10(9)(d) for the base year and test year according to Western's general ledger chart of accounts.
f. Are the jurisdictional adjustments in Volume 10, FR 10(10)(d) and FR 10(9)(d) for the base year and test year by account as Western would submit to the Commission in a FERC Form No. 2 annual report? If not, resubmit these schedules according to the FERC accounts.
g. Are the operating revenue and expenses in Volume 10, FR 10(10)(c), Schedule C-2.1 and Schedule C-2.2 according to FERC Form No. 2 as filed annually with the Commission available? If no, resubmit these schedules according to the FERC accounts.

Response:

a. Yes, the operating revenue and expenses as presented in Western's referenced schedules are according to the NARUC chart of accounts.
b. No, the budget was not prepared by NARUC accounts.
c. This is not available per our response to a and b above.
d. The current schedule as filed is by Western's chart of accounts.
e. Resubmission of FR 10(9)(d) is attached.
f. Attached is a resubmission of FR 10(10)(d), see "e" above for FR 10(9)(d).
g. Resubmission of FR 10(10)(c), Schedule C-2.1 and Schedule C-2.2 are attached.

Western Kentucky Gas Company
Case No. 99-070
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
For the 12 Months ended December 31, 2000

Data:__X____Base Period__X____Forecasted Period
Type of Filing:___X_____Original________Updated
Workpaper Reference No(s).____________

FR 10(10)(d)1
Schedule D-1
Sheet 1 of 4

Line No.	ACCOUNT No. & Title	Base Period	D-2.1 ADJ 1	D-2.1 ADJ 2	D-2.1 ADJ 3									Total ADJUST.
					Title of Adjustment									
	SALE of Gas													
1	480 Gas Rev - Residential	56,881,573	11,467,472											11,467,472
2	481 Gas Rev - Commericial & Industrial	33,188,281	3,415,008											3,415,008
5	483 Gas Rev - Public Authority & Other	5,339,280	1,701,359											1,701,359
6														
7	Total SALE of Gas	95,409,134	16,583,839	0	0	0	0	0	0	0	0	0	16,583,839
8														
9	Other Operating Income													
10	488 MISC. Service Revenues	782,607		(37,606)										(37,606)
11	489 Revenue From Transporting Gas to OtherS	8,541,563		(786,207)										(786,207)
12	495 Other Gas Service Revenue	21,175		(11,176)										(11,176)
13														
14	Total Other Operating Income	9,345,345	0	(834,989)	0	0	0	0	0	0	0	0	(834,989)
15														
16	Total Operating Revenue	104,754,479	16,583,839	(834,989)	0	0	0	0	0	0	0	0	15,748,850
17														
18	Other Gas Supply Expenses - Operation													
19	804 Gas Purchase Costs	62,724,103			14,798,055									14,798,055
20														
21	Total Other Gas Supply Expenses - Operation	62,724,103	0	0	14,798,055	0	0	0	0	0	0	0	0	14,798,055
22														
23	Total Plant Revenue	42,030,376	16,583,839	(834,989)	(14,798,055)	0	0	0	0	0	0	0	0	950,795
24														
25	Blended Effective Tax Rate	40.36%	6,693,652	(337,022)	(5,972,865)	0	0	0	0	0	0	0	0	383,765
26														
27	NET Operating Income Impact		9,890,187	(497,967)	(8,825,190)	0	0	0	0	0	0	0	0	567,030

Western Kentucky Gas Company
Case No. 99-070
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
For the 12 Months ended December 31, 2000

Data:__X___Base Period__X___Forecasted Period
Type of Filing:__X____Original_______Updated
Workpaper Reference No(s)._________

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Schedule D-1
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Line No.	ACCOUNT No. & Title	Base Period	D-2.2 ADJ 1	D-2.2 ADJ 2	D-2.2 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	D-2.2 ADJ 6	D-2.2 ADJ 7	D-2.2 ADJ 8	Total OperationS	GRAND Total ADJUST.
			Title of Adjustment									
1	756 Production Field Measuring & Regulating	(57)	19						2,593		2,612	2,612
2	766 Production Maintenance Field Measurement	145	39						(184)		(145)	(145)
3	798 Other Exploraton	(48)							48		48	48
4	807 Purchased Gas Expense	15,291	1,669		(18)				717		2,368	2,368
5	814 Storage Supervision & Engineering	(10,994)	75		(1)				25,482		25,556	25,556
6	816 Storage Wells Expense	57,607	7,333		(79)				(4,288)		2,966	2,966
7	817 Storage Lines Expense	50,617	6,270		(68)				(6,747)		(545)	(545)
8	818 Storage Compressor Station	44,201	6,975		(75)				(2,198)		4,702	4,702
9	819 Storage Compressor Station Fuel	14,087							5,317		5,317	5,317
10	820 Storage Measuring & Regulating	32,058	3,710		(40)				8,062		11,732	11,732
11	821 Storage Purification	16,491	3,109		(34)				14,762		17,837	17,837
12	824 Storage Other Expense	771	114		(1)				6,825		6,938	6,938
13	825 Storage Royalties	27,106							14,483		14,483	14,483
14	831 Storage Maintenance Structure	3,291	71		(1)				(3,272)		(3,202)	(3,202)
15	832 Storage Maintenance Res	734	144		(2)				432		574	574
16	834 Storage Maintenance Compressor	6,399	507		(5)				8,636		9,138	9,138
17	835 Storage Maintenance Meas/Reg	5,017	70		(1)				10,986		11,055	11,055
18	836 Storage Maintenance Purification	5,671	258		(3)				9,258		9,513	9,513
19	841 Storage Operation	507	135		(1)				(641)		(507)	(507)
20	847 Storage Maintenance	554	114		(1)				(95)		18	18
21	850 Trsm Supervision & Engineering	33,039	6,147		(67)				(23,914)		(17,834)	(17,834)
22	856 Trsm Mains Expense	240,395	27,325	(1,085)	(296)				(15,767)		10,177	10,177
23	857 Trsm Measuring & Regulating	86,157	15,406		(167)				(12,968)		2,271	2,271
24	859 Trsm Other Exp	1,302	346		(4)				(1,644)		(1,302)	(1,302)
25	862 Trsm Structure & Improvements	4,584	155		(2)				15,187		15,340	15,340
26	863 Trsm Maint of Mains	10,805	90		(1)				798		887	887
27	864 Trsm Maint Comp Sta Equip	(85)	51		(1)				1,479		1,529	1,529
28	865 Trsm Maint Meas/Reg Sta	12,319	2,585		(28)				21,112		23,669	23,669
29	867 Trsm Maint Other Eq	70	62		(1)				2,953		3,014	3,014
30	870 Dist Supervision & Engineering	2,755,920	206,454		(2,233)	15,664	148,758		(739)		367,904	367,904
31	871 Dist Load Dispatching	284,417	8,296	5,000	(90)				(11,051)		2,155	2,155
32	872 Dist Comp Sta	19	5						(24)		(19)	(19)
33	874 Dist Main/Ser Exp	1,936,184	446,689	(4,397)	(4,834)	10,541		1,317	(358,556)		90,760	90,760
34	875 Dist Meas/Reg Sta-Gen	104,611	14,303		(155)				(12,508)		1,640	1,640
35	876 Dist Meas/Reg Sta-Ind	234,996	33,242		(360)				1,517		34,399	34,399
36	877 Dist Meas/Reg Sta-Cty.	197,961	23,760		(257)				(19,956)		3,547	3,547
37	878 Dist Mtr/House Reg	1,519,596	387,058	(438)	(4,189)	8,145			(42,203)		348,373	348,373
38	879 Dist Cust Install	663,090	148,444	(509)	(1,606)				(15,646)		130,683	130,683
39	880 Dist Other Exp	52,009	2,226		(24)				18,490		20,692	20,692
40	881 Dist Rents	1,304,880							(79,570)		(79,570)	(79,570)
41	885 Dist Maint Super/Eng	456,325	120,724		(1,306)				(85,868)		33,550	33,550
42	886 Dist Maint Struc/Improv	8,331							8,584		8,584	8,584

Western Kentucky Gas Company
Case No. 99-070
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
For the 12 Months ended December 31, 2000

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Sheet 3 of 4

Line No.	ACCOUNT No. & Title	Base Period	D-2.2 ADJ 1	D-2.2 ADJ 2	D-2.2 ADJ 3	D-2.2 ADJ 4	D-2.2 ADJ 5	D-2.2 ADJ 6	D-2.2 ADJ 7	D-2.2 ADJ 8	Total OperationS	GRAND Total ADJUST.
			Title of Adjustment									
1	887 Dist Maint of Mains	76,655	6,184		(67)	413			15,242		21,772	21,772
2	889 Dist Maint Meas/Reg Sta-Gen	28,455	687		(7)				(6,422)		(5,742)	(5,742)
3	890 Dist Maint Meas/Reg Sta-Ind	43,108	3,892		(42)				15,374		19,224	19,224
4	891 Dist Maint Meas/Reg Sta-Cty	58,721	2,624		(28)				(10,528)		(7,932)	(7,932)
5	892 Dist Maint of Ser	28,021	2,263		(24)				92,706		94,945	94,945
6	893 Dist Maint Mtr/House Reg	30,397	453		(5)				(2,296)		(1,848)	(1,848)
7	894 Dist Maint Other Eq	38,465	23						1,165		1,188	1,188
8	901 Cust Accts Supervision	1,779	(350)		4				1,876		1,530	1,530
9	902 Cust Accts Mtr Exp	1,043,770	141,142		(1,527)				(141,572)		(1,957)	(1,957)
10	903 Cust Accts Records/Collections	64,355	6,195		(67)				(10,569)		(4,441)	(4,441)
11	904 Cust Accts Uncoll Accts	474,701								143,879	143,879	143,879
12	907 Cust Ser Supervision	462,262	58,330		(633)		13,490				71,187	71,187
13	908 Cust Ser Assist Exp	587,187	9,787		(106)	(62,810)	20,062		(342,000)		(375,067)	(375,067)
14	909 Cust Ser Info Adv Exp	65,812				(2,048)					(2,048)	(2,048)
15	911 Sales Promo Supervision	12,547	986		(11)	(1,080)	2,020				1,915	1,915
16	912 Sales Promo Demo/Selling	47,031	2,192		(24)	(9,462)	4,493				(2,801)	(2,801)
17	916 Sales Promo Misc Promo	1,902							(1,902)		(1,902)	(1,902)
18	921 Adm Gen Office Supply	52							(52)		(52)	(52)
19	923 Adm Gen Outside Services Emply	11,768						(11,768)			(11,768)	(11,768)
20	925 Adm Gen Injuries/Damages	76,837	7,616		(82)				17,629		25,163	25,163
21	926 Adm Gen Empl Pen/Ben	553,082							574,918		574,918	574,918
22	927 Adm Gen Franchise Req	83,558							35,703		35,703	35,703
23	928 Adm Gen Reg Comm Exp								110,000		110,000	110,000
24	9301 Adm Gen Goodwill Adv	20							(20)		(20)	(20)
25	9302 Adm Gen Gen Exp	39,780							6,903		6,903	6,903
26	935 Adm Gen Maint Gen Plant	378							(377)		(377)	(377)
27												
28	Total	14,007,015	1,716,004	(1,429)	(18,570)	(40,637)	188,823	(10,451)	(164,340)	143,879	1,813,279	1,813,279
29												
30												
31												
32	NET Labor/Benefits	8,344,138	1,716,004								1,716,004	1,716,004
33	Materials/Supplie	375,991		(1,429)							(1,429)	(1,429)
34	Transportation	878,736			(18,570)						(18,570)	(18,570)
35	Departmental Specfic	1,914,866				(40,637)					(40,637)	(40,637)
36	Administration	1,169,322					188,823				188,823	188,823
37	Outside Services	173,199						(10,451)			(10,451)	(10,451)
38	Other Departmental Direct	667,542							(164,340)		(164,340)	(164,340)
39	Revenue/Reimbursements	483,221										
40										143,879	143,879	143,879
41	Total	14,007,015	1,716,004	(1,429)	(18,570)	(40,637)	188,823	(10,451)	(164,340)	143,879	1,813,279	1,813,279
42												
43	Blended Effective Tax Rate	40.36%	(692,622)	577	7,495	16,402	(76,214)	4,218	66,332	(58,073)	(731,885)	(97,449)
44												
45	NET Operating Income Impact		1,023,382	(852)	(11,075)	(24,235)	112,609	(6,233)	(98,008)	85,806	1,081,394	(715,278)

Western Kentucky Gas Company
Case No. 99-070
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
For the 12 Months ended December 31, 2000

Data:__X___Base Period__X___Forecasted Period
Type of Filing:__X____Original_______Updated
Workpaper Reference No(s).

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Schedule D-1
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Line No.	ACCOUNT No. & Title	Base Period	Title of Adjustment: D-2.3 ADJ 1	D-2.3 ADJ 2	Total ADJUST.
1	403 DEPRECIATION Expense	7,899,611	1,704,360		1,704,360
2	404 Amortization Expense	48			0
3	406 AMORT. - Gas Plant AQUIST.	204,981			0
4					
5	Total DEPRECIATION and Amortization	8,104,640	1,704,360		1,704,360
6					
7	Blended Effective Tax Rate	40.36%	687,922		687,922
8					
9	NET Operating Income Impact		1,016,438		1,016,438
10					
11					
12					
13					
14	408 Taxes, Other than Income	2,227,174		(275,174)	(275,174)
15					
16	Blended Effective Tax Rate	40.36%		(111,067)	(111,067)
17					
18	NET Operating Income Impact			(164,107)	(164,107)

WESTERN KENTUCKY GAS COMPANY
Case #99-070
Base Year Oct 1998 - Sep 1999

	INCOME STATEMENT	Oct ACT	Nov ACT	Dec ACT	Jan ACT	Feb ACT	Mch ACT	Apr	May	Jun	Jul	Aug	Sep	Total
	Operating Revenues:													
480-482	Gas service revenue	$5,922	$9,635	$12,444	$15,777	$10,855	$11,446	$8,459	$5,380	$3,789	$3,736	$3,726	$4,239	$95,408
489	Transportation	739	686	778	840	754	843	703	658	634	633	633	641	8,542
488,495	Other revenue	64	97	82	73	58	75	60	60	60	55	60	60	804
	Total Operating Revenues	6,725	10,418	13,304	16,690	11,667	12,364	9,222	6,098	4,483	4,424	4,419	4,940	104,754
800-805	Purchase gas	4,072	6,324	8,356	10,788	7,145	7,763	5,818	3,418	2,189	2,153	2,149	2,549	62,724
	Gross Profit	2,653	4,094	4,948	5,902	4,522	4,601	3,404	2,680	2,294	2,271	2,270	2,391	42,030
	Operating expenses:													
750-935	Direct O&M	1,395	1,080	1,076	1,235	827	1,065	1,263	1,253	1,106	1,231	1,220	1,257	14,008
920-935	Shared Services Billing	904	854	945	854	1,121	654	796	763	767	790	775	780	10,003
403-406	Depreciation & amortization	574	564	569	569	666	575	764	764	764	765	764	765	8,103
408	Taxes - other than income	173	162	194	306	213	219	160	160	160	160	160	160	2,227
409	Provision for income taxes	(353)	407	837	1,114	725	616	41	(237)	(337)	(413)	(394)	(340)	1,666
	Total operating expenses	2,693	3,067	3,621	4,078	3,552	3,129	3,024	2,703	2,460	2,533	2,525	2,622	36,007
	Operating income(loss)	(40)	1,027	1,327	1,824	970	1,472	380	(23)	(166)	(262)	(255)	(231)	6,023
	Other income:													
415-416	Merchandising	(56)	(61)	240	13	8	22	30	30	30	30	30	30	346
419	Interest and dividends	1	13	7	6	5	4	2	2	2	2	2	2	48
421426	Other non-operating inc/exp	(32)	(35)	(302)	(22)	(22)	(18)	(9)	(9)	(9)	(9)	(9)	(9)	(485)
421	PBR	91	373	363	127	363	127	131	123	118	103	123	180	2,222
	Total other income	4	290	308	124	354	135	154	146	141	126	146	203	2,131
	Interest Charges:													
431-432		524	560	446	427	456	451	474	474	474	474	473	473	5,706
	Total interest charges	524	560	446	427	456	451	474	474	474	474	473	473	5,706
	Net Income	($560)	$757	$1,189	$1,521	$868	$1,156	$60	($351)	($499)	($610)	($582)	($501)	$2,448

WESTERN KENTUCKY GAS COMPANY
Case #99-070
Test Year Jan 2000 - Dec 2000

	INCOME STATEMENT	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Operating Revenues:													
480-482	Gas service revenue	$20,306	$16,405	$12,552	$7,436	$4,876	$3,389	$3,383	$3,342	$3,781	$7,051	$11,815	$17,657	$111,993
489	*Transportation*	804	752	694	621	580	558	557	557	564	616	684	768	7,755
488495	Other revenue	61	66	62	55	50	48	47	50	59	70	109	78	755
	Total Operating Revenues	21,171	17,223	13,308	8,112	5,506	3,995	3,987	3,949	4,404	7,737	12,608	18,503	120,503
800-805	Purchase gas	14,996	11,919	8,922	4,962	2,993	1,860	1,863	1,832	2,169	4,699	8,386	12,921	77,522
	Gross Profit	6,175	5,304	4,386	3,150	2,513	2,135	2,124	2,117	2,235	3,038	4,222	5,582	42,981
	Operating expenses:													
750-935	*Direct O&M*	1,378	1,339	1,238	1,338	1,381	1,226	1,347	1,382	1,191	1,357	1,348	1,295	15,820
920-935	Shared Services Billing	833	817	811	846	813	817	840	825	830	903	858	860	10,053
403-406	Depreciation & amortization	817	817	817	817	817	817	817	818	818	818	818	818	9,809
480	Taxes - other than income	163	163	163	163	163	163	163	162	162	162	162	163	1,952
409	Provision for income taxes	1,059	734	398	(161)	(425)	(519)	(587)	(590)	(445)	(218)	272	826	344
	Total operating expenses	4,250	3,870	3,427	3,003	2,749	2,504	2,580	2,597	2,556	3,022	3,458	3,962	37,978
	Operating income(loss)	1,925	1,434	959	147	(236)	(369)	(456)	(480)	(321)	16	764	1,620	5,003
	Other income:													
415-416	Merchandising	29	30	30	30	30	30	30	30	30	30	30	29	358
419	Interest and dividends	2	2	2	2	2	3	3	3	3	3	3	2	30
421,426	Other non-operating inc/exp	(9)	(9)	(9)	(9)	(8)	(8)	(8)	(8)	(9)	(9)	(9)	(9)	(104)
421	PBR	158	168	146	131	123	118	103	123	180	178	155	117	1,700
	Total other income	180	191	169	154	147	143	128	148	204	202	-179	139	1,984
	Interest Charges:													
431-432	Total interest charges	540	540	540	540	540	540	540	540	540	540	540	539	6,479
	Total interest charges	540	540	540	540	540	540	540	540	540	540	540	539	6,479
	Net Income	1,565	$1,085	$588	($239)	($629)	($766)	($868)	($872)	($657)	($322)	$403	1,220	$508

Western Kentucky Gas Company
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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility (1) $	Allocation Percentage (2) %	Unadjusted Jurisdiction (3) $	Jurisdictional Method/ Description (4)
1		OPERATING REVENUE				
2		Sales of Gas				
3	480	Residential	56,881,573	100.00	56,881,573	100%
4	481	Commercial and Industrial	33,188,281	100.00	33,188,281	
5	482	Other - Public Authority	5,339,280	100.00	5,339,280	
6						
7						
8		Total Sales of Gas	95,409,134		95,409,134	
9						
10		Other Operating Income				
11	487	Forfeited Discounts	0	100.00	0	
12	488	Misc. Service Revenues	782,607	100.00	782,607	
13	489	Revenue From Transportation of Gas of Others	8,541,563	100.00	8,541,563	
14	495	Other Gas Revenue	21,175	100.00	21,175	
15		Total Other Operating Income	9,345,345	100.00	9,345,345	
16						
17		TOTAL OPERATING REVENUE	104,754,479		104,754,479	
18						
19		OPERATING EXPENSES				
20		Production Expense - Operation				
21	750	Natural Gas Op. Supervision & Engineering	0	100.00	0	
22	756	Ng. Field Meas. & Reg. Station	(57)	100.00	(57)	
23	758	Ng. Well Royalties	0	100.00	0	
24	807	Purchased Gas Expense	15,291	100.00	15,291	
25		Total Production Expense - Operation	15,234		15,234	
26						
27		Production Expense - Maintenance				
28	742	Mfg. Production Maint.	0	100.00	0	
29	766/798	Ng. Field Meas. & Reg. Station	98	100.00	98	
30		Total Production Expense - Maintenance	98		98	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
1		Natural Gas Storage Expense - Operation				
2	814	Operation Supervision & Engineering	(10,994)	100.00	(10,994)	100%
3	816	Wells Expense	57,607	100.00	57,607	
4	817	Lines Expense	50,617	100.00	50,617	
5	818	Compressor Station Expense	44,201	100.00	44,201	
6	819	Compressor Station Expense Fuel & Power	14,088	100.00	14,088	
7	820	Measuring & Regulating Station Expense	32,058	100.00	32,058	
8	821	Purification	16,491	100.00	16,491	
9	824	Other	771	100.00	771	
10	825	Storage Well Royalties	27,107	100.00	27,107	
11		Total Nat. Gas Storage Expense - Operation	231,945		231,945	
12						
13		Natural Gas Storage Expense - Maintenance				
14	831	Structure & Improvements	3,291	100.00	3,291	
15	832	Reservoirs & Wells	734	100.00	734	
16	834	Compressor Station Equip.	6,399	100.00	6,399	
17	835	Measuring & Regulating Station Equip.	5,017	100.00	5,017	
18	836	Purification Equipment	5,672	100.00	5,672	
19	841/847	Other Storage Exp. - LNG	1,061	100.00	1,061	
20		Total Nat. Gas Storage Expense - Maintenance	22,172		22,172	
21						
22		Transmission Expense - Operation				
23	850	Operation Supervision & Engineering	33,039	100.00	33,039	
24	856	Mains Expense	240,395	100.00	240,395	
25	857	Measuring & Regulating Station Exp.	86,157	100.00	86,157	
26	859	Other Exp.	1,302	100.00	1,302	
27		Total Transmission Expense - Operation	360,893		360,893	
28						
29		Transmission Expense - Maintenance				
30	862	Structures & Improvements	4,584	100.00	4,584	
31	863	Mains	10,805	100.00	10,805	
32	864	Compressor Station Equipment	(85)	100.00	(85)	
33	865	Measuring & Reg Station Equip.	12,319	100.00	12,319	
34	867	Other Equipment	70	100.00	70	
35		Total Transmission Expense - Maintenance	27,693		27,693	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
1						
2		Purchased Gas Cost - Operation				
3	803	Natural Gas Purchases	58,363,119	100.00	58,363,119	100%
4	804	Natural Gas City Gate Purchases	4,368,918	100.00	4,368,918	
5	805	Other Gas Purchases / Gas Cost Adjustments	0	100.00	0	
6	806	Exchange Gas	0	100.00	0	
7	808	Gas Withdrawn From Storage	0	100.00	0	
8	809	Gas Delivered to Storage	0	100.00	0	
9	812	Gas Used for Other Utility Operations	(7,933)	100.00	(7,933)	
10		Total Purchased Gas Cost	62,724,104		62,724,104	
11						
12		Distribution Expenses - Operation				
13	870	Supervision and Engineering	2,941,956	100.00	2,941,956	
14	871	Distribution Load Dispatching	284,417	100.00	284,417	
15	872	Compressor Station Labor & Expenses	19	100.00	19	
16	874	Mains & Services	1,891,810	100.00	1,891,810	
17	875	Measuring and Regulating Station Exp. - Gen	104,612	100.00	104,612	
18	876	Measuring and Regulating Station Exp. - Ind.	234,996	100.00	234,996	
19	877	Measuring and Regulating Sta. Exp. - City Gate	197,961	100.00	197,961	
20	878	Meters and House Regulator Expense	1,522,089	100.00	1,522,089	
21	879	Customer Installations Expense	664,515	100.00	664,515	
22	880	Other Expense	52,009	100.00	52,009	
23	881	Rents	1,304,880	100.00	1,304,880	
24		Total Distribution Expenses - Operation	9,199,263		9,199,263	
25						
26		Distribution Expenses - Maintenance				
27	885	Supervision and Engineering	488,551	100.00	488,551	
28	886	Structures and Improvements	8,331	100.00	8,331	
29	887	Mains	45,141	100.00	45,141	
30	889	Measuring and Regulating Station Exp. - Gen	28,455	100.00	28,455	
31	890	Measuring and Regulating Station Exp. - Ind.	43,107	100.00	43,107	
32	891	Measuring and Regulating Sta. Exp. - City Gate	58,721	100.00	58,721	
33	892	Services	28,021	100.00	28,021	
34	893	Meters and House Regulators	30,397	100.00	30,397	
35	894	Other Equipment	38,465	100.00	38,465	
36		Total Distribution Expenses - Maintenance	769,190		769,190	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility (1)	Allocation Percentage (2)	Unadjusted Jurisdiction (3)	Jurisdictional Method/ Description (4)
1		Customer Accounts Expenses - Operation				
2	901	Supervision	1,779	100.00	1,779	100%
3	902	Meter Reading Expenses	1,043,764	100.00	1,043,764	
4	903	Customer Records & Collections	272,585	100.00	272,585	
5	904	Uncollectible Accounts	474,701	100.00	474,701	
6	905	Miscellaneous Customer Accounts Expenses	0	100.00	0	
7		Total Customer Accounts Expense	1,792,828		1,792,828	
8						
9		Customer Service & Information - Operation				
10	907	Supervision	462,262	100.00	462,262	
11	908	Customer Assistance Expenses	588,374	100.00	588,374	
12	909	Informational and Instructional Advertising Expenses	65,812	100.00	65,812	
13		Total Customer Accounts Expenses - Operation	1,116,448		1,116,448	
14						
15		Sales Expense				
16	911	Supervision	12,548	100.00	12,548	
17	912	Demonstrating and Selling Expenses	47,382	100.00	47,382	
18	913	Promotional Advertising Expense	0	100.00	0	
19	916	Miscellaneous Sales Expense	1,902	100.00	1,902	
20		Total Sales Expenses	61,832		61,832	
21						
22		Administrative and General Expenses - Operation				
23	920	Administrative and General Salaries	0	100.00	0	
24	921	Office Supplies and Expenses	16,212	100.00	16,212	
25	922	Administrative Expense Transferred	9,050,095	100.00	9,050,095	
26	923	Outside Services Employed	79,921	100.00	79,921	
27	924	Property Insurance	20,393	100.00	20,393	
28	925	Injuries and Damages	349,259	100.00	349,259	
29	926	Employee Pensions and Benefits	742,765	100.00	742,765	
30	927	Franchise Requirements	83,557	100.00	83,557	
31	928	Regulatory Commission Expense	6,828	100.00	6,828	
32	930.01	Institutional/Goodwill Advertising Expenses	20	100.00	20	
33	930.02	Miscellaneous General Expense	62,174	100.00	62,174	
34		Total Administrative and General Exp. - Operation	10,411,226		10,411,226	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
			$	%	$	
1		Administrative and General Expense - Maintenance				
2	935	Maintenance of General Plant	376	100.00	376	100%
3		Total Administrative and Gen. Exp. - Maintenance	376		376	
4						
5		Total Operation and Maintenance Expense	86,733,301	100.00	86,733,301	
6						
7	403-406	Depreciation and Amortization	8,104,641	100.00	8,104,641	
8	408	Taxes Other than Income Taxes	2,227,173	100.00	2,227,173	
9	409	Provision for Federal & State Income Taxes	1,667,114	100.00	1,667,114	
10					0	
11		TOTAL OPERATING EXPENSE (incl Gas Cost)	98,732,229	100.00	98,732,229	
12					0	
13		NET OPERATING INCOME	6,022,250	100.00	6,022,250	

Western Kentucky Gas Company
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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
			$	%	$	
1		OPERATING REVENUE				
2		Sales of Gas				
3	480	Residential	68,349,045	100.00	68,349,045	100%
4	481	Commercial and Industrial	36,603,289	100.00	36,603,289	
5	482	Other - Public Authority	7,040,639	100.00	7,040,639	
6						
7		Total Sales of Gas	111,992,973		111,992,973	
8						
9		Other Operating Income				
10	487	Forfeited Discounts	0	100.00	0	
11	488	Misc. Service Revenues	745,001	100.00	745,001	
12	489	Revenue From Transportation of Gas of Others	7,755,356	100.00	7,755,356	
13	495	Other Gas Revenue	9,999	100.00	9,999	
14		Total Other Operating Income	8,510,356	100.00	8,510,356	
15						
16		TOTAL OPERATING REVENUE	120,503,329		120,503,329	
17						
18		OPERATING EXPENSES				
19		Production Expense - Operation				
20	750	Natural Gas Op. Supervision & Engineering	0	100.00	0	
21	756	Ng. Field Meas. & Reg. Station	2,555	100.00	2,555	
22	758	Ng. Well Royalties	0	100.00	0	
23	807	Purchased Gas Expense	17,659	100.00	17,659	
24		Total Production Expense - Operation	20,214		20,214	
25						
26		Production Expense - Maintenance				
27	742	Mfg. Production Maint.	0	100.00	0	
28	766	Ng. Field Meas. & Reg. Station	0	100.00	0	
29		Total Production Expense - Maintenance	0		0	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
1		Natural Gas Storage Expense - Operation				
2	814	Operation Supervision & Engineering	14,562	100.00	14,562	100%
3	816	Wells Expense	60,574	100.00	60,574	
4	817	Lines Expense	50,071	100.00	50,071	
5	818	Compressor Station Expense	48,902	100.00	48,902	
6	819	Compressor Station Expense Fuel & Power	19,405	100.00	19,405	
7	820	Measuring & Regulating Station Expense	43,790	100.00	43,790	
8	821	Purification	34,328	100.00	34,328	
9	824	Other	7,708	100.00	7,708	
10	825	Storage Well Royalties	41,589	100.00	41,589	
11		Total Nat. Gas Storage Expense - Operation	320,929		320,929	
12						
13		Natural Gas Storage Expense - Maintenance				
14	831	Structure & Improvements	89	100.00	89	
15	832	Reservoirs & Wells	1,308	100.00	1,308	
16	834	Compressor Station Equip.	15,537	100.00	15,537	
17	835	Measuring & Regulating Station Equip.	16,072	100.00	16,072	
18	836	Purification Equipment	15,185	100.00	15,185	
19	847	Maint. Other Storage Exp. - LNG	572	100.00	572	
20		Total Nat. Gas Storage Expense - Maintenance	48,763		48,763	
21						
22		Transmission Expense - Operation				
23	850	Operation Supervision & Engineering	15,205	100.00	15,205	
24	856	Mains Expense	250,572	100.00	250,572	
25	857	Measuring & Regulating Station Exp.	88,428	100.00	88,428	
26	859	Other Exp.	0	100.00	0	
27		Total Transmission Expense - Operation	354,205		354,205	
28						
29		Transmission Expense - Maintenance				
30	862	Structures & Improvements	19,925	100.00	19,925	
31	863	Mains	11,692	100.00	11,692	
32	864	Compressor Station Equipment	1,444	100.00	1,444	
33	865	Measuring & Reg Station Equip.	35,989	100.00	35,989	
34	867	Other Equipment	3,084	100.00	3,084	
35		Total Transmission Expense - Maintenance	72,133		72,133	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
1						
2		Purchased Gas Cost - Operation				
3	803	Natural Gas Purchases	77,522,158	100.00	77,522,158	100%
4	804	Natural Gas City Gate Purchases	0	100.00	0	
5	805	Other Gas Purchases / Gas Cost Adjustments	0	100.00	0	
6	806	Exchange Gas	0	100.00	0	
7	808	Gas Withdrawn From Storage	0	100.00	0	
8	809	Gas Delivered to Storage	0	100.00	0	
9	812	Gas Used for Other Utility Operations	0	100.00	0	
10		Total Purchased Gas Cost	77,522,158		77,522,158	
11						
12		Distribution Expenses - Operation				
13	870	Supervision and Engineering	3,123,823	100.00	3,123,823	
14	871	Distribution Load Dispatching	286,572	100.00	286,572	
15	872	Compressor Station Labor & Expenses	0	100.00	0	
16	874	Mains & Services	2,026,944	100.00	2,026,944	
17	875	Measuring and Regulating Station Exp. - Gen	106,251	100.00	106,251	
18	876	Measuring and Regulating Station Exp. - Ind.	269,395	100.00	269,395	
19	877	Measuring and Regulating Sta. Exp. - City Gate	201,508	100.00	201,508	
20	878	Meters and House Regulator Expense	1,867,968	100.00	1,867,968	
21	879	Customer Installations Expense	793,773	100.00	793,773	
22	880	Other Expense	72,702	100.00	72,702	
23	881	Rents	1,225,310	100.00	1,225,310	
24		Total Distribution Expenses - Operation	9,974,246		9,974,246	
25						
26		Distribution Expenses - Maintenance				
27	885	Supervision and Engineering	489,874	100.00	489,874	
28	886	Structures and Improvements	16,915	100.00	16,915	
29	887	Mains	98,427	100.00	98,427	
30	889	Measuring and Regulating Station Exp. - Gen	22,713	100.00	22,713	
31	890	Measuring and Regulating Station Exp. - Ind.	62,332	100.00	62,332	
32	891	Measuring and Regulating Sta. Exp. - City Gate	50,789	100.00	50,789	
33	892	Services	122,966	100.00	122,966	
34	893	Meters and House Regulators	28,548	100.00	28,548	
35	894	Other Equipment	39,653	100.00	39,653	
36		Total Distribution Expenses - Maintenance	932,217		932,217	

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Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
1		Customer Accounts Expenses - Operation				
2	901	Supervision	3,310	100.00	3,310	100%
3	902	Meter Reading Expenses	1,041,813	100.00	1,041,813	
4	903	Customer Records & Collections	59,915	100.00	59,915	
5	904	Uncollectible Accounts	618,580	100.00	618,580	
6	905	Miscellaneous Customer Accounts Expenses	0	100.00	0	
7		Total Customer Accounts Expense	1,723,618		1,723,618	
8					0	
9		Customer Service & Information - Operation			0	
10	907	Supervision	533,449	100.00	533,449	
11	908	Customer Assistance Expenses	212,121	100.00	212,121	
12	909	Informational and Instructional Advertising Expenses	63,764	100.00	63,764	
13		Total Customer Accounts Expenses - Operation	809,334		809,334	
14					0	
15		Sales Expense			0	
16	911	Supervision	14,462	100.00	14,462	
17	912	Demonstrating and Selling Expenses	44,230	100.00	44,230	
18	913	Promotional Advertising Expense	0	100.00	0	
19	916	Miscellaneous Sales Expense	0	100.00	0	
20		Total Sales Expenses	58,692		58,692	
21						
22		Administrative and General Expenses - Operation				
23	920	Administrative and General Salaries	0	100.00	0	
24	921	Office Supplies and Expenses	0	100.00	0	
25	922	Administrative Expense Transferred	10,052,965	100.00	10,052,965	
26	923	Outside Services Employed	0	100.00	0	
27	924	Property Insurance	0	100.00	0	
28	925	Injuries and Damages	102,000	100.00	102,000	
29	926	Employee Pensions and Benefits	1,128,000	100.00	1,128,000	
30	927	Franchise Requirements	119,261	100.00	119,261	
31	928	Regulatory Commission Expense	110,000	100.00	110,000	
32	930.01	Institutional/Goodwill Advertising Expenses	0	100.00	0	
33	930.02	Miscellaneous General Expense	46,679	100.00	46,679	
34		Total Administrative and General Exp. - Operation	11,558,905		11,558,905	

Western Kentucky Gas Company
Case No. 99-070
Operating Revenue and Expenses by NARUC Account
For the Forecasted Period 12 Months ended December 31, 2000

Data:_______Base Period__X___Forecasted Period
Type of Filing:__X____Original_______Updated
Workpaper Reference No(s). Sched. I-2; Sched. C-2.2

DR 67 (g)
Schedule C-2.1
Sheet 10 of 10

Line No.	Account No. (S)	Account Title	Unadjusted Total Utility	Allocation Percentage	Unadjusted Jurisdiction	Jurisdictional Method/ Description
			(1)	(2)	(3)	(4)
			$	%	$	
1		Administrative and General Expense - Maintenance				
2	935	Maintenance of General Plant	0	100.00	0	100%
3		Total Administrative and Gen. Exp. - Maintenance	0		0	
4						
5		Total Operation and Maintenance Expense	103,395,413	100.00	103,395,413	
6					0	
7	403-406	Depreciation and Amortization	9,809,000	100.00	9,809,000	
8	408	Taxes Other than Income Taxes	1,952,000	100.00	1,952,000	
9	409	Provision for Federal & State Income Taxes	344,000	100.00	344,000	
10					0	
11		TOTAL OPERATING EXPENSE	115,500,413	100.00	115,500,413	
12					0	
13		NET OPERATING INCOME	5,002,916	100.00	5,002,916	

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 68
Witness: Betty L. Adams

<u>Data Request:</u>

Refer to Volume 2 of 10 of the Application, Tab 4, the Testimony of Betty L. Adams. On page 6, line 24, a table is presented to point out Western's overall operating and maintenance ("O & M") budgeting effectiveness for FY 1994 through 1998. Provide the source documents from which this table was created, with amounts detailed according to Western's general ledger chart of accounts.

<u>Response:</u>

Attached are copies of the "Responsibility Management Report" for the FY 1994 through 1998. The report which is referenced as RESP-10 is the budget and actual for the categories that we used in our budgeting process. The report referenced RESP-30 is by NARUC account for actual expenses only according to Western's general ledger chart of accounts.

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY ELEMENT GROUP
FOR THE MONTH ENDED 09/29/98

REF: RESP-10
ISSUED 11/07/98

THIS MONTH ACTUAL	THIS MONTH BUDGET	THIS MONTH FAV(UNFAV) COMPARED TO BUDGET	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR		YEAR TO DATE ACTUAL	YEAR TO DATE BUDGET	YEAR TO DATE FAV(UNFAV) COMPARED TO BUDGET	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
8,598	7,235	(19)%	6,944	(24)%	EXECUTIVE PAYROLL	95,101	85,980	(11)%	82,627	(15)%
161,452	137,719	(17)%	213,652	24 %	EXEMPT PAYROLL	1,805,637	1,881,871	4 %	2,316,795	22 %
431,693	431,814	0 %	558,789	23 %	OPERATING PAYROLL	5,653,106	6,035,438	6 %	6,453,672	12 %
23,038	173,032	87 %	332,630	93 %	EMPLOYEE BENEFITS	1,823,234	2,401,028	24 %	2,774,749	34 %
624,781	749,800	17 %	1,112,015	44 %	TOTAL COMPANY LABOR	9,377,078	10,404,317	10 %	11,627,843	19 %
52,199	23,712	(120)%	36,807	(42)%	MATERIALS & SUPPLIES	444,275	338,943	(31)%	376,479	(18)%
69,133	58,706	(18)%	58,815	(18)%	TRANSPORTATION	791,467	704,680	(12)%	663,822	(19)%
					OTHER:					
226,259	226,588	0 %	223,532	(1)%	DEPARTMENTAL SPECIFIC	2,066,620	2,409,878	14 %	2,075,668	0 %
114,201	27,422	(316)%	51,555	(122)%	ADMINISTRATIVE	938,295	334,844	(180)%	295,234	(218)%
21,966	6,555	(235)%	7,360	(198)%	OUTSIDE SERVICES	163,822	79,860	(105)%	123,906	(32)%
74,716	53,644	(39)%	8,420	(787)%	OTHER DEPARTMENT DIRE	626,509	711,527	12 %	436,892	(43)%
28	45,160	100 %	101,107	100 %	ALLOCATIONS & OTHER	256,227	729,099	65 %	668,413	62 %
437,170	359,369	(22)%	391,974	(12)%	TOTAL OTHER	4,051,473	4,265,208	5 %	3,600,113	(13)%
1,183,283	1,191,587	1 %	1,599,611	26 %	TOTAL INCURRED COST	14,664,293	15,713,148	7 %	16,268,257	10 %
161,366	213,779	24 %	9,118	(1669)%	REV/REIMBRSEMNTS/UNCOLL	696,309	393,200	(77)%	459,372	(52)%
1,344,649	1,405,366	4 %	1,608,729	16 %	TOTAL NET EXPENSES	15,360,602	16,106,348	5 %	16,727,629	8 %

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) 745,746

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 05/31/99

PAGE: 1
REF: RESP-30
ISSUED 06/26/99

************ THIS MONTH ************					************ YEAR TO DATE ************		
ACTUAL	LAST YR	FAV(UNFAV) COMPARED TO LST YR	NARUC	ACCOUNT:	ACTUAL	LAST YR	FAV(UNFAV) COMPARED TO LST YR
0	2	100 %	742	MFG GAS PROD-MAINT-PROD EQUIP	0	2	100 %
0	0	0 %	750	NG PROD-OPT-SUPRV & ENGRNG	0	126	100 %
0	116	100 %	756	NG PROD-OPT-FIELD MEAS & REG	71	839	92 %
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	0	100	100 %
135	0	(100)%	766	NG PROD-MAINT-FIELD MEAS & REG	563	0	(100)%
0	101	100 %	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	(48)	787	106 %
1,717	2,226	23 %	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	10,212	14,003	27 %
0	0	0 %	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	(7,402)	(2,557)	189 %
5,664	5,525	(3)%	816	NG STORG-UNDRGRND-OPT-WELLS EXP	37,363	41,644	10 %
4,588	4,680	2 %	817	NG STORG-UNDRGRND-OPT-LINES EXP	33,853	32,839	(3)%
5,095	4,811	(6)%	818	NG STORG-UNDRGRND-OPT-COMP EXP	21,593	38,768	44 %
2,355	118	(1896)%	819	NG STORG-UNDRGRND-OPT-COMP PWR	13,403	4,221	(218)%
2,418	3,073	21 %	820	NG STORG-UNDRGRND-OPT-MEAS REG	17,599	21,946	20 %
717	2,331	69 %	821	NG STORG-UNDRGRND-OPT-PURIF EXP	20,183	26,501	24 %
949	279	(240)%	824	NG STORG-UNDRGRND-OPT-OTHER EXP	3,062	3,646	16 %
991	4,449	78 %	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	20,693	29,537	30 %
405	196	(107)%	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	7,206	2,449	(194)%
771	0	(100)%	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	3,249	527	(517)%
628	0	(100)%	833	NG STORG-UNDRGRND-MAINT OF LINES	1,113	51	(2082)%
256	1,057	76 %	834	NG STORG-UNDRGRND-MAINT COMP STN	4,020	4,560	12 %
916	402	(128)%	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	1,286	640	(101)%
309	146	(112)%	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	2,614	898	(191)%
0	0	0 %	841	NG STOR-UNDRGRD-MISCODING	507	0	(100)%
0	0	0 %	847	OTHR STRG EXP-MNT LIQ EQUIP	554	0	(100)%
3,479	1,420	(145)%	850	TRANS-OPT-SUPRV & ENGINEERING	31,175	6,593	(373)%
2,624	18,216	86 %	856	TRANS-OPT MAINS EXPENSES	141,349	142,489	1 %
5,332	8,097	34 %	857	TRANS-OPT MEA & REG STAT EXP	90,388	79,328	(14)%
743	0	(100)%	859	TRANS-OPT-OTHER EXPENSES	2,045	0	(100)%
946	81	(1068)%	862	TRANS-MAINT-STRUCT & IMPROVMENTS	1,869	1,782	(5)%
255	0	(100)%	863	TRANS-MAINT-MAINT OF MAINS	10,540	2,319	(355)%
0	0	0 %	864	TRANS-MAINT COMP ST EQUIP	169	62	(173)%
17,069	3,118	(447)%	865	TRANS-MAINT-MEAS & REG STATN EQUIP	40,936	18,195	(125)%
0	0	0 %	867	TRANS-MAINT OTH EQUIPMENT	570	489	(17)%
154,679	226,243	32 %	870	DISTRIB-OPT-SUPRV & ENGINEERING	1,617,085	1,341,400	(21)%
5,704	26,348	78 %	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	109,629	227,900	52 %
0	0	0 %	872	DISTRIB-OPT-COMP STAT LABOR & EXPENSE	19	72	74 %
60,845	127,977	52 %	874	DISTRIB-OPT-MAINS & SERVICES	1,231,779	931,264	(32)%
3,335	5,221	36 %	875	DISTRIB-OPT-MEAS & REG STAT-GEN	72,307	60,303	(20)%
15,870	18,428	14 %	876	DISTRIB-OPT-MEAS & REG STAT-IND	170,468	156,959	(9)%
952	20,144	95 %	877	DISTRIB-OPT-MEAS & REG CITY GATE	134,495	133,139	(1)%
125,848	111,116	(13)%	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,086,466	847,697	(28)%
40,014	44,895	11 %	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	365,090	491,683	26 %
1,660	2,782	40 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	20,806	29,530	30 %
101,512	110,047	8 %	881	DISTRIB-OPT-RENTS/BLDG SRV	799,247	848,289	6 %
29,679	33,344	11 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	290,256	262,589	(11)%
7,364	2,017	(265)%	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	11,836	13,004	9 %
7,560	6,056	(25)%	887	DISTRIB-MAINT-MAINT OF MAINS	52,722	33,700	(56)%
2,717	1,110	(145)%	889	DISTRIB-MEAS & REG STAT - GEN	16,433	3,773	(336)%

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 05/31/99

REF: RESP-30
ISSUED 06/26/99

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV (UNFAV) COMPARED TO LST YR	ACCOUNT	DESCRIPTION	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV (UNFAV) COMPARED TO LST YR
3,193	5,594	43 %	890	DISTRIB-MEAS & REG STAT - IND	26,273	24,554	(7)%
5,565	4,632	(20)%	891	DISTRIB-MEAS & REG STAT - CITY GATE	26,598	22,980	(16)%
4,168	3,356	(24)%	892	DISTRIB-MAINT OF SERVICE	18,695	10,882	(72)%
2,794	29,055	90 %	893	DISTRIB-MTRS & HOUSE REG	5,529	219,595	97 %
298	1,070	72 %	894	DISTRIB-MAINT-OTHER EQUIPMENT	15,562	6,140	(153)%
0	3,094	100 %	901	CUS ACT EX-OPT-SUPERVISION	(968)	141,664	101 %
83,332	86,637	4 %	902	CUS ACT EX-OPT-METER READING EXP	706,952	695,454	(2)%
7,943	6,640	(20)%	903	CUS ACT EX-OPT-CUS REC/COLL EXP	51,307	652,294	92 %
25,407	86,813	71 %	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	444,361	460,800	4 %
168	0	(100)%	905	CUS ACT EX-OPT-MISC CUST AC EXP	168	20	(740)%
29,629	25,902	(14)%	909	CUS SRV EXP-OPT-SUPERVISION	289,928	130,511	(122)%
14,274	49,058	71 %	910	CUS SRV EXP-OPT-CUSTMR ASSIST	256,585	607,669	58 %
3,123	(12,264)	(125)%	911	CUST SRV EXP-OPT-INFRM ADV EXP	57,302	46,263	(24)%
575	868	34 %	915	SALE PROMO EXP-OPT-SUPERVISION	7,365	5,512	(34)%
1,841	1,653	(11)%	916	SALE PROMO EXP-OPT-DEMO & SELL	24,207	34,305	29 %
0	0	0 %	917	SALE PROMO EXP-OPT-PROMO ADV	0	1,022	100 %
908	855	(6)%	918	SALE PROMO EXP-OPT-MISC PROMO	2,810	2,586	(9)%
0	5,968	100 %	920	ADM&GEN EX-OPT-ADM&GEN SALARY	0	11,100	100 %
0	12	100 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	52	17	(206)%
0	0	0 %	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	11,768	2,727	(332)%
16	20,913	100 %	925	A&G EX-OPT INJR&DAMG INS DR/CR	31,221	83,616	63 %
(30,905)	199,822	115 %	926	A&G EX-OPT-EMP WELF/PENS DR/CR	(82,064)	1,519,296	105 %
0	10,875	100 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	60,686	12,785	(375)%
0	0	0 %	9301	A&G EX-OPT-INSTL/GOODWILL ADV	20	0	(100)%
2,625	11,630	77 %	9302	A&G EX-OPT-MISC GENERAL EXP	33,634	36,720	8 %
0	0	0 %	932	A&G EX-MAINT - GENERAL PLANT	376	0	(100)%
771,055	1,338,355	42 %		TOTAL NET EXPENSES	8,477,740	10,582,598	20 %

LAST PAGE OF REPORT

ATMOS [illegible]Y CORPORATION
WESTERN [illegible]NTUCKY GAS COMPANY

RESPON[illegible]IBILITY [illegible]GEMENT REPORT
BY ELEM[illegible] GROUP
FOR THE MONTH ENDED 09/29/97

PAGE:
REF: RESP-[illegible]
ISSUED 11/11/97

CO DIV W

THIS MONTH ACTUAL	THIS MONTH BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR		YEAR TO DATE ACTUAL	BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
6,944	6,981	1 %	6,689	(4)%	EXECUTIVE PAYROLL	82,627	82,896	0 %	79,472	(4)%
213,652	225,545	5 %	182,445	(17)%	EXEMPT PAYROLL	2,316,795	2,675,542	13 %	2,304,569	(1)%
558,789	558,318	0 %	528,873	(6)%	OPERATING PAYROLL	6,453,672	6,619,072	2 %	6,325,378	(2)%
332,630	213,398	(56)%	195,868	(70)%	EMPLOYEE BENEFITS	2,774,749	2,531,941	(10)%	1,779,242	(56)%
1,112,015	1,004,242	(11)%	913,875	(22)%	TOTAL COMPANY LABOR	11,627,843	11,909,451	2 %	10,488,661	(11)%
36,807	30,071	(22)%	49,345	25 %	MATERIALS & SUPPLIES	376,479	441,258	15 %	421,886	11 %
58,815	47,128	(25)%	51,776	(14)%	TRANSPORTATION	663,822	582,680	(14)%	602,873	(10)%
					OTHER:					
223,532	181,317	(23)%	144,496	(55)%	DEPARTMENTAL SPECIFIC	2,075,668	2,146,899	3 %	1,539,544	(35)%
51,515	30,601	(68)%	28,002	(84)%	ADMINISTRATIVE	295,193	447,981	34 %	265,341	(11)%
7,360	33,930	78 %	35,510	79 %	OUTSIDE SERVICES	123,906	587,611	79 %	168,715	27 %
8,420	12,808	34 %	(34,486)	(124)%	OTHER DEPARTMENT DIRE	436,892	225,427	(94)%	208,038	(110)%
101,107	36,255	(179)%	124,371	19 %	ALLOCATIONS & OTHER	668,413	435,392	(54)%	661,489	(1)%
391,934	294,911	(33)%	297,893	(32)%	TOTAL OTHER	3,600,072	3,843,310	6 %	2,843,127	(27)%
1,599,571	1,376,352	(16)%	1,312,889	(22)%	TOTAL INCURRED COST	16,268,216	16,776,699	3 %	14,356,547	(13)%
0	0	100 %	0	100 %	ALLOCATIONS - OUT	0	(601,604)	(100)%	0	100 %
9,118	(220,906)	(104)%	227,180	95 %	REV/REIMBRSEMNTS/UNCOLL	459,372	109,953	(317)%	368,000	(25)%
1,608,689	1,155,446	(39)%	1,540,069	(4)%	TOTAL NET EXPENSES	16,727,588	16,285,048	(3)%	14,724,547	(14)%

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) (442,540)

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/97

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	NARUC ACCOUNT		YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
183	0	(100)%	756	NG PROD-OPT-FIELD MEAS & REG	1,227	190	(546)%
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
9	0	(100)%	766	NG PROD-MAINT-FIELD MEAS & REG	1,957	1,872	(5)%
94	94	0 %	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,132	1,106	(2)%
1,175	618	(90)%	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	22,182	38,670	43 %
(643)	720	189 %	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	2,386	13,185	82 %
9,268	2,423	(283)%	816	NG STORG-UNDRGRND-OPT-WELLS EXP	75,904	52,362	(45)%
1,970	1,620	(22)%	817	NG STORG-UNDRGRND-OPT-LINES EXP	36,415	36,373	0 %
7,420	7,410	0 %	818	NG STORG-UNDRGRND-OPT-COMP EXP	89,630	83,034	(8)%
7,354	8,739	16 %	819	NG STORG-UNDRGRND-OPT-COMP PWR	24,647	48,308	49 %
1,414	332	(326)%	820	NG STORG-UNDRGRND-OPT-MEAS REG	20,768	25,800	20 %
552	3,040	82 %	821	NG STORG-UNDRGRND-OPT-PURIF EXP	25,072	24,288	(3)%
514	433	(19)%	824	NG STORG-UNDRGRND-OPT-OTHER EXP	5,453	5,611	3 %
1,927	1,733	(11)%	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	37,477	34,803	(8)%
1,297	1,297	0 %	826	NG STORG-UNDRGRND-OPT-RENTS	15,560	15,560	0 %
51	0	(100)%	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	4,922	433	(1037)%
0	0	0 %	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	784	3,686	79 %
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	0	754	100 %
0	246	100 %	834	NG STORG-UNDRGRND-MAINT COMP STN	6,150	14,029	56 %
0	0	0 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	4,128	13,177	69 %
47	0	(100)%	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	4,714	3,156	(49)%
0	1,586	100 %	850	TRANS-OPT-SUPRV & ENGINEERING	9,538	19,656	51 %
28,097	37,225	25 %	856	TRANS-OPT MAINS EXPENSES	197,509	197,924	0 %
16,768	7,105	(136)%	857	TRANS-OPT MEA & REG STAT EXP	124,273	117,779	(6)%
0	0	0 %	860	TRANS-OPT-RENTS	0	500	100 %
0	1,163	100 %	862	TRANS-MAINT-STRUCT & IMPROVMENTS	3,610	4,893	26 %
193	9,345	98 %	863	TRANS-MAINT-MAINT OF MAINS	8,120	13,006	38 %
2,604	9,566	73 %	865	TRANS-MAINT-MEAS & REG STATN EQUIP	39,700	65,884	40 %
172,234	119,064	(45)%	870	DISTRIB-OPT-SUPRV & ENGINEERING	1,606,629	1,404,065	(14)%
29,581	35,247	16 %	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	365,348	439,395	17 %
98,562	91,391	(8)%	874	DISTRIB-OPT-MAINS & SERVICES	1,056,501	1,010,604	(5)%
10,337	7,646	(35)%	875	DISTRIB-OPT-MEAS & REG STAT-GEN	103,121	112,604	8 %
22,113	21,875	(1)%	876	DISTRIB-OPT-MEAS & REG STAT-IND	273,892	276,453	1 %
12,215	10,958	(11)%	877	DISTRIB-OPT-MEAS & REG CITY GATE	188,874	168,932	(12)%
132,141	124,094	(6)%	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,208,555	1,158,541	(4)%
83,554	61,391	(36)%	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	817,656	691,742	(18)%
6,648	7,160	7 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	55,046	72,543	24 %
106,910	109,015	2 %	881	DISTRIB-OPT-RENTS/BLDG SRV	1,254,419	1,181,012	(6)%
48,503	36,062	(34)%	885	DISTRIB-MAINT-SUPRV/ENGINEERING	460,675	439,703	(5)%
653	12,695	95 %	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	22,267	26,893	17 %
8,305	30,143	72 %	887	DISTRIB-MAINT-MAINT OF MAINS	103,242	100,690	(3)%
610	1,401	56 %	889	DISTRIB-MEAS & REG STAT - GEN	15,270	15,777	3 %
4,290	8,217	48 %	890	DISTRIB-MEAS & REG STAT - IND	47,018	64,273	27 %
3,752	8,780	57 %	891	DISTRIB-MEAS & REG STAT - CITY GATE	59,930	49,233	(22)%
3,731	2,267	(65)%	892	DISTRIB-MAINT OF SERVICE	22,469	43,151	48 %
37,713	2,192	(1620)%	893	DISTRIB-MTRS & HOUSE REG	186,360	61,750	(202)%
154	28	(450)%	894	DISTRIB-MAINT-OTHER EQUIPMENT	9,034	4,414	(105)%
27,922	29,443	5 %	901	CUS ACT EX-OPT-SUPERVISION	342,423	380,569	10 %

AIMOS [redacted]Y CORPORATION
WESTERN[redacted]NTUCKY GAS COMPANY

RESPONSIBILITY [redacted]GEMENT REPORT
BY NARUC-F[redacted] ACCOUNT
FOR THE MONTH ENDED 09/29/97

PAGE: [redacted]
REF: RESP[redacted]
ISSUED 11/11/97

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	ACCOUNT	DESCRIPTION	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
86,010	80,062	(7)%	902	CUS ACT EX-OPT-METER READING EXP	1,053,793	1,005,362	(5)%
173,082	166,101	(4)%	903	CUS ACT EX-OPT-CUS REC/COLL EXP	2,051,670	2,039,473	(1)%
(1,531)	221,114	101 %	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	501,885	431,207	(16)%
9,981	8,546	(17)%	909	CUS SRV EXP-OPT-SUPERVISION	106,085	97,118	(9)%
95,177	(53,746)	(277)%	910	CUS SRV EXP-OPT-CUSTMR ASSIST	959,355	371,209	(158)%
12,763	0	(100)%	911	CUST SRV EXP-OPT-INFRM ADV EXP	86,229	1,303	(6518)%
783	267	(193)%	915	SALE PROMO EXP-OPT-SUPERVISION	3,963	3,212	(23)%
2,460	85,529	97 %	916	SALE PROMO EXP-OPT-DEMO & SELL	52,238	281,882	81 %
0	135	100 %	917	SALE PROMO EXP-OPT-PROMO ADV	0	1,925	100 %
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	5,281	3,135	(68)%
0	54	100 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	142	211	33 %
6,107	7,661	20 %	925	A&G EX-OPT INJR&DAMG INS DR/CR	91,662	155,339	41 %
333,433	204,721	(63)%	926	A&G EX-OPT-EMP WELF/PENS DR/CR	2,797,081	1,740,897	(61)%
0	0	0 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	19,323	13,494	(43)%
200	5,860	97 %	9302	A&G EX-OPT-MISC GENERAL EXP	36,795	40,298	9 %
1,608,687	1,540,068	(4)%		TOTAL NET EXPENSES	16,727,589	14,724,548	(14)%

LAST PAGE OF REPORT

LINE 2

ATMOS E[redacted]Y CORPORATION
WESTERN[redacted]TUCKY

RESPONSIBILITY [redacted]GEMENT REPORT
BY ELEM[redacted]GROUP
FOR THE MONTH ENDED 09/29/96

PAGE: [redacted]
REF: RESP-[redacted]
ISSUED 10/30/96

CO DIV W

THIS MONTH ACTUAL	THIS MONTH BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR		YEAR TO DATE ACTUAL	BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
6,689	8,183	18 %	7,878	15 %	EXECUTIVE PAYROLL	79,472	98,317	19 %	93,592	15 %
182,445	220,334	17 %	202,207	10 %	EXEMPT PAYROLL	2,304,569	2,642,910	13 %	2,419,191	5 %
528,873	554,592	5 %	524,260	(1)%	OPERATING PAYROLL	6,325,378	6,653,697	5 %	6,128,566	(3)%
195,868	234,850	17 %	89,984	(118)%	EMPLOYEE BENEFITS	1,779,242	2,818,484	37 %	2,374,212	25 %
913,875	1,017,959	10 %	824,329	(11)%	TOTAL COMPANY LABOR	10,488,661	12,213,408	14 %	11,015,561	5 %
49,345	24,222	(104)%	34,664	(42)%	MATERIALS & SUPPLIES	421,886	416,645	(1)%	340,022	(24)%
51,776	76,547	32 %	33,531	(54)%	TRANSPORTATION	602,873	920,781	35 %	743,003	19 %
					OTHER:					
144,496	144,667	0 %	136,433	(6)%	DEPARTMENTAL SPECIFIC	1,539,544	1,699,372	9 %	1,471,447	(5)%
28,002	26,259	(7)%	40,307	31 %	ADMINISTRATIVE	265,341	363,133	27 %	269,385	2 %
35,510	17,052	(108)%	9,950	(257)%	OUTSIDE SERVICES	168,715	177,507	5 %	126,249	(34)%
(34,486)	9,945	447 %	53,277	165 %	OTHER DEPARTMENT DIRE	208,038	182,028	(14)%	204,078	(2)%
124,371	64,477	(93)%	49,984	(149)%	ALLOCATIONS & OTHER	661,489	891,170	26 %	518,300	(28)%
297,893	262,400	(14)%	289,951	(3)%	TOTAL OTHER	2,843,127	3,313,210	14 %	2,589,459	(10)%
1,312,889	1,381,128	5 %	1,182,475	(11)%	TOTAL INCURRED COST	14,356,547	16,864,044	15 %	14,688,045	2 %
0	(64,118)	(100)%	0	100 %	ALLOCATIONS - OUT	0	(1,104,393)	(100)%	0	100 %
227,180	(83,245)	(372)%	(191,289)	(218)%	REV/REIMBRSEMNTS/UNCOLL	368,000	242,572	(51)%	105,196	(250)%
1,540,069	1,233,765	(25)%	991,186	(55)%	TOTAL NET EXPENSES	14,724,547	16,002,223	8 %	14,793,241	0 %

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) 1,277,676

LAST PAGE OF REPORT

LINE2

ATMOS E[illegible]Y CORPORATION
WESTERN [illegible]TUCKY

RESPONSIBILITY [illegible]GEMENT REPORT
BY NARUC-F[illegible] ACCOUNT
FOR THE MONTH [illegible]NDED 09/29/96

REF: RESP[illegible]
ISSUED 10/30/96

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	NARUC ACCOUNT:		YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
0	0	0 %	756	NG PROD-OPT-FIELD MEAS & REG	190	461	59 %
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
0	0	0 %	766	NG PROD-MAINT-FIELD MEAS & REG	1,872	737	(154)%
94	89	(6)%	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,106	1,042	(6)%
618	2,079	70 %	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	38,670	39,314	2 %
720	1,345	46 %	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	13,185	14,050	6 %
2,423	3,835	37 %	816	NG STORG-UNDRGRND-OPT-WELLS EXP	52,362	53,017	1 %
1,620	2,871	44 %	817	NG STORG-UNDRGRND-OPT-LINES EXP	36,373	40,834	11 %
7,410	4,636	(60)%	818	NG STORG-UNDRGRND-OPT-COMP EXP	83,034	75,808	(10)%
8,739	355	(2362)%	819	NG STORG-UNDRGRND-OPT-COMP PWR	48,308	35,729	(35)%
332	823	60 %	820	NG STORG-UNDRGRND-OPT-MEAS REG	25,800	19,938	(29)%
3,040	267	(1039)%	821	NG STORG-UNDRGRND-OPT-PURIF EXP	24,288	14,281	(70)%
433	(1,104)	(139)%	824	NG STORG-UNDRGRND-OPT-OTHER EXP	5,611	4,930	(14)%
1,733	4,848	64 %	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	34,803	35,335	2 %
1,297	1,297	0 %	826	NG STORG-UNDRGRND-OPT-RENTS	15,560	15,560	0 %
0	0	0 %	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	433	476	9 %
0	62	100 %	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	3,686	1,569	(135)%
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	754	1,082	30 %
246	94	(162)%	834	NG STORG-UNDRGRND-MAINT COMP STN	14,029	14,912	6 %
0	0	0 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	13,177	698	(1788)%
0	81	100 %	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	3,156	2,491	(27)%
1,586	1,088	(46)%	850	TRANS-OPT-SUPRV & ENGINEERING	19,656	17,909	(10)%
37,225	26,867	(39)%	856	TRANS-OPT MAINS EXPENSES	197,924	211,161	6 %
7,105	10,299	31 %	857	TRANS-OPT MEA & REG STAT EXP	117,779	117,171	(1)%
0	0	0 %	860	TRANS-OPT-RENTS	500	625	20 %
1,163	1,642	29 %	862	TRANS-MAINT-STRUCT & IMPROVMENTS	4,893	5,141	5 %
9,345	326	(2767)%	863	TRANS-MAINT-MAINT OF MAINS	13,006	7,594	(71)%
9,566	10,545	9 %	865	TRANS-MAINT-MEAS & REG STATN EQUIP	65,884	33,080	(99)%
119,064	129,970	8 %	870	DISTRIB-OPT-SUPRV & ENGINEERING	1,404,065	1,503,518	7 %
35,247	26,375	(34)%	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	439,395	420,828	(4)%
91,391	78,938	(16)%	874	DISTRIB-OPT-MAINS & SERVICES	1,010,604	915,943	(10)%
7,646	4,260	(79)%	875	DISTRIB-OPT-MEAS & REG STAT-GEN	112,604	43,981	(156)%
21,875	22,699	4 %	876	DISTRIB-OPT-MEAS & REG STAT-IND	276,453	275,743	0 %
10,958	9,814	(12)%	877	DISTRIB-OPT-MEAS & REG CITY GATE	168,932	156,629	(8)%
124,094	92,001	(35)%	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,158,541	1,044,956	(11)%
61,391	68,813	11 %	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	691,742	726,544	5 %
7,160	12,768	44 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	72,543	90,835	20 %
109,015	99,626	(9)%	881	DISTRIB-OPT-RENTS/BLDG SRV	1,181,012	1,138,324	(4)%
36,062	36,920	2 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	439,703	446,145	1 %
12,695	10,542	(20)%	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	26,893	27,310	2 %
30,143	10,957	(175)%	887	DISTRIB-MAINT-MAINT OF MAINS	100,690	68,085	(48)%
1,401	1,707	18 %	889	DISTRIB-MEAS & REG STAT - GEN	15,777	13,583	(16)%
8,217	6,604	(24)%	890	DISTRIB-MEAS & REG STAT - IND	64,273	48,237	(33)%
8,780	7,402	(19)%	891	DISTRIB-MEAS & REG STAT - CITY GATE	49,233	41,335	(19)%
2,267	2,694	16 %	892	DISTRIB-MAINT OF SERVICE	43,151	49,211	12 %
2,192	3,704	41 %	893	DISTRIB-MTRS & HOUSE REG	61,750	62,871	2 %
28	655	96 %	894	DISTRIB-MAINT-OTHER EQUIPMENT	4,414	10,940	60 %
29,443	32,292	9 %	901	CUS ACT EX-OPT-SUPERVISION	380,569	398,826	5 %

LINE 2

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/96

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	ACCOUNT	DESCRIPTION	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
80,062	75,989	(5)%	902	CUS ACT EX-OPT-METER READING EXP	1,005,362	984,061	(2)%
166,101	148,750	(12)%	903	CUS ACT EX-OPT-CUS REC/COLL EXP	2,039,473	1,818,708	(12)%
221,114	(198,034)	(212)%	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	431,207	171,653	(151)%
8,546	8,960	5 %	909	CUS SRV EXP-OPT-SUPERVISION	97,118	105,442	8 %
(53,746)	32,198	267 %	910	CUS SRV EXP-OPT-CUSTMR ASSIST	371,209	377,949	2 %
0	120	100 %	911	CUST SRV EXP-OPT-INFRM ADV EXP	1,303	52,266	98 %
267	479	44 %	915	SALE PROMO EXP-OPT-SUPERVISION	3,212	6,278	49 %
85,529	48,349	(77)%	916	SALE PROMO EXP-OPT-DEMO & SELL	281,882	442,252	36 %
135	145	7 %	917	SALE PROMO EXP-OPT-PROMO ADV	1,925	1,896	(2)%
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	3,135	5,720	45 %
54	524	90 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	211	793	73 %
0	0	0 %	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	0	1,759	100 %
7,661	(17,279)	(144)%	925	A&G EX-OPT INJR&DAMG INS DR/CR	155,339	22,483	(591)%
204,721	155,409	(32)%	926	A&G EX-OPT-EMP WELF/PENS DR/CR	1,740,897	2,504,069	30 %
0	1,391	100 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	13,494	13,523	0 %
5,860	3,100	(89)%	9302	A&G EX-OPT-MISC GENERAL EXP	40,298	35,500	(14)%
1,540,068	991,187	(55)%		TOTAL NET EXPENSES	14,724,548	14,793,241	0 %

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

RESPONSIBILITY MANAGEMENT REPORT
BY ELEMENT GROUP
FOR THE MONTH ENDED 09/29/95

CO DIV W

THIS MONTH ACTUAL	THIS MONTH BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR		YEAR TO DATE ACTUAL	BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
7,878	7,879	0 %	7,552	(4)%	EXECUTIVE PAYROLL	93,592	94,548	1 %	89,119	(5)%
202,207	226,462	11 %	204,458	1 %	EXEMPT PAYROLL	2,419,191	2,714,970	11 %	2,402,435	(1)%
524,260	568,133	8 %	509,144	(3)%	OPERATING PAYROLL	6,128,566	6,819,704	10 %	6,480,974	5 %
89,984	232,760	61 %	267,054	66 %	EMPLOYEE BENEFITS	2,374,212	2,792,472	15 %	2,774,170	14 %
824,329	1,035,234	20 %	988,208	17 %	TOTAL COMPANY LABOR	11,015,561	12,421,694	11 %	11,746,698	6 %
34,664	33,709	(3)%	42,141	18 %	MATERIALS & SUPPLIES	340,022	412,014	17 %	434,212	22 %
33,531	85,106	61 %	3,530	(850)%	TRANSPORTATION	743,003	1,017,184	27 %	728,547	(2)%
					OTHER:					
136,433	140,840	3 %	130,898	(4)%	DEPARTMENTAL SPECIFIC	1,471,447	1,626,653	10 %	1,374,085	(7)%
40,307	26,610	(51)%	29,241	(38)%	ADMINISTRATIVE	269,385	335,225	20 %	299,587	10 %
9,950	11,990	17 %	6,100	(63)%	OUTSIDE SERVICES	126,249	147,048	14 %	228,265	45 %
53,277	15,247	(249)%	15,398	(246)%	OTHER DEPARTMENT DIRE	204,078	187,252	(9)%	168,911	(21)%
49,984	32,375	(54)%	57,126	13 %	ALLOCATIONS & OTHER	518,300	506,354	(2)%	417,089	(24)%
289,951	227,062	(28)%	238,763	(21)%	TOTAL OTHER	2,589,459	2,802,532	8 %	2,487,937	(4)%
1,182,475	1,381,111	14 %	1,272,642	7 %	TOTAL INCURRED COST	14,688,045	16,653,424	12 %	15,397,394	5 %
0	(110,686)	(100)%	0	100 %	ALLOCATIONS - OUT	0	(1,328,251)	(100)%	0	100 %
(191,289)	(249,548)	(23)%	166,279	215 %	REV/REIMBRSEMNTS/UNCOLL	105,196	186,077	43 %	346,977	70 %
991,186	1,020,877	3 %	1,438,921	31 %	TOTAL NET EXPENSES	14,793,241	15,511,250	5 %	15,744,371	6 %

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) 718,021

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/95

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	NARUC	ACCOUNT	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
0	0	0 %	723	MFG GAS PROD-OPT-FUEL-L/P GAS	0	1,826	100 %
0	6,549	100 %	735	MFG GAS PROD-OPT-MISC PROD EXP	0	6,756	100 %
0	0	0 %	752	NG PROD-OPT-GAS WELLS EXP	0	69	100 %
0	140	100 %	756	NG PROD-OPT-FIELD MEAS & REG	461	1,717	73 %
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
0	16	100 %	766	NG PROD-MAINT-FIELD MEAS & REG	737	1,777	59 %
89	84	(6)%	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,042	1,042	0 %
2,079	1,599	(30)%	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	39,314	29,345	(34)%
1,345	1,163	(16)%	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	14,050	12,261	(15)%
3,835	2,855	(34)%	816	NG STORG-UNDRGRND-OPT-WELLS EXP	53,017	64,335	18 %
2,871	1,886	(52)%	817	NG STORG-UNDRGRND-OPT-LINES EXP	40,834	33,765	(21)%
4,636	4,165	(11)%	818	NG STORG-UNDRGRND-OPT-COMP EXP	75,808	76,806	1 %
355	6,045	94 %	819	NG STORG-UNDRGRND-OPT-COMP PWR	35,729	35,622	0 %
823	1,249	34 %	820	NG STORG-UNDRGRND-OPT-MEAS REG	19,938	30,803	35 %
267	1,376	81 %	821	NG STORG-UNDRGRND-OPT-PURIF EXP	14,281	29,863	52 %
(1,104)	377	393 %	824	NG STORG-UNDRGRND-OPT-OTHER EXP	4,930	6,391	23 %
4,848	1,802	(169)%	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	35,335	39,235	10 %
1,297	1,297	0 %	826	NG STORG-UNDRGRND-OPT-RENTS	15,560	15,560	0 %
0	58	100 %	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	476	942	49 %
62	48	(29)%	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	1,569	3,892	60 %
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	1,082	43	(2416)%
94	214	56 %	834	NG STORG-UNDRGRND-MAINT COMP STN	14,912	7,455	(100)%
0	401	100 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	698	4,699	85 %
81	0	(100)%	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	2,491	1,266	(97)%
1,088	1,464	26 %	850	TRANS-OPT-SUPRV & ENGINEERING	17,909	17,499	(2)%
26,867	32,696	18 %	856	TRANS-OPT MAINS EXPENSES	211,161	242,789	13 %
10,299	6,606	(56)%	857	TRANS-OPT MEA & REG STAT EXP	117,171	136,858	14 %
0	2	100 %	859	TRANS-OPT-OTHER EXPENSES	0	2	100 %
0	0	0 %	860	TRANS-OPT-RENTS	625	512	(22)%
1,642	0	(100)%	862	TRANS-MAINT-STRUCT & IMPROVMENTS	5,141	1,615	(218)%
326	912	64 %	863	TRANS-MAINT-MAINT OF MAINS	7,594	8,048	6 %
10,545	1,969	(436)%	865	TRANS-MAINT-MEAS & REG STATN EQUIP	33,080	40,029	17 %
129,970	131,767	1 %	870	DISTRIB-OPT-SUPRV & ENGINEERING	1,503,518	1,520,984	1 %
26,375	31,382	16 %	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	420,828	399,116	(5)%
0	0	0 %	872	DISTRIB-OPT-COMP STAT LABOR & EXPENSE	0	46	100 %
78,938	62,485	(26)%	874	DISTRIB-OPT-MAINS & SERVICES	915,943	1,139,060	20 %
4,260	11,319	62 %	875	DISTRIB-OPT-MEAS & REG STAT-GEN	43,981	60,067	27 %
22,699	23,052	2 %	876	DISTRIB-OPT-MEAS & REG STAT-IND	275,743	275,252	0 %
9,814	13,478	27 %	877	DISTRIB-OPT-MEAS & REG CITY GATE	156,629	166,365	6 %
92,001	88,520	(4)%	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,044,956	1,159,170	10 %
68,813	63,342	(9)%	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	726,544	755,500	4 %
12,768	10,144	(26)%	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	90,835	90,519	0 %
99,626	101,497	2 %	881	DISTRIB-OPT-RENTS/BLDG SRV	1,138,324	1,109,810	(3)%
36,920	36,876	0 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	446,145	473,380	6 %
10,542	7,411	(42)%	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	27,310	25,797	(6)%
10,957	(14,974)	(173)%	887	DISTRIB-MAINT-MAINT OF MAINS	68,085	136,945	50 %
1,707	3,422	50 %	889	DISTRIB-MEAS & REG STAT - GEN	13,583	22,663	40 %
6,604	6,433	(3)%	890	DISTRIB-MEAS & REG STAT - IND	48,237	61,092	21 %

ATMOS RGY CORPORATION
WESTER KENTUCKY

RESPONSIBILITY AGEMENT REPORT
BY NARUC- C ACCOUNT
FOR THE MONTH ENDED 09/29/95

PAGE:
REF: RESP 30
ISSUED 10/31/95

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	ACCOUNT	DESCRIPTION	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
7,402	2,922	(153)%	891	DISTRIB-MEAS & REG STAT - CITY GATE	41,335	44,070	6 %
2,694	2,998	10 %	892	DISTRIB-MAINT OF SERVICE	49,211	73,521	33 %
3,704	5,395	31 %	893	DISTRIB-MTRS & HOUSE REG	62,871	55,854	(13)%
655	1,622	60 %	894	DISTRIB-MAINT-OTHER EQUIPMENT	10,940	14,259	23 %
32,292	31,692	(2)%	901	CUS ACT EX-OPT-SUPERVISION	398,826	271,469	(47)%
75,989	65,194	(17)%	902	CUS ACT EX-OPT-METER READING EXP	984,061	951,110	(3)%
148,750	148,964	0 %	903	CUS ACT EX-OPT-CUS REC/COLL EXP	1,818,708	1,914,821	5 %
(198,034)	159,084	224 %	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	171,653	436,574	61 %
8,960	11,417	22 %	909	CUS SRV EXP-OPT-SUPERVISION	105,442	125,559	16 %
32,198	29,393	(10)%	910	CUS SRV EXP-OPT-CUSTMR ASSIST	377,949	322,541	(17)%
120	2,978	96 %	911	CUST SRV EXP-OPT-INFRM ADV EXP	52,266	18,993	(175)%
479	861	44 %	915	SALE PROMO EXP-OPT-SUPERVISION	6,278	12,903	51 %
48,349	56,153	14 %	916	SALE PROMO EXP-OPT-DEMO & SELL	442,252	411,331	(8)%
145	265	45 %	917	SALE PROMO EXP-OPT-PROMO ADV	1,896	2,644	28 %
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	5,720	4,598	(24)%
524	39	(1244)%	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	793	1,181	33 %
0	5,000	100 %	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	1,759	10,024	82 %
(17,279)	(2,627)	558 %	925	A&G EX-OPT INJR&DAMG INS DR/CR	22,483	197,160	89 %
155,409	270,227	42 %	926	A&G EX-OPT-EMP WELF/PENS DR/CR	2,504,069	2,689,143	7 %
1,391	0	(100)%	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	13,523	10,078	(34)%
0	(4,982)	(100)%	929	A&G EX-OPT DUPLICATE CHRGS - CR	0	(103,413)	(100)%
3,100	1,200	(158)%	9302	A&G EX-OPT-MISC GENERAL EXP	35,500	31,265	(14)%
991,187	1,438,922	31 %		TOTAL NET EXPENSES	14,793,241	15,744,373	6 %

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY ELEMENT GROUP
FOR THE MONTH ENDED 09/29/94

REF: RESP-10
ISSUED 09/05/95

THIS MONTH ACTUAL	THIS MONTH BUDGET	FAV(UNFAV) COMPARED TO BUDGET	THIS MONTH LAST YR	FAV(UNFAV) COMPARED TO LST YR		YEAR TO DATE ACTUAL	YEAR TO DATE BUDGET	FAV(UNFAV) COMPARED TO BUDGET	YEAR TO DATE LAST YR	FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
7,552	7,295	(4)%	6,993	(8)%	EXECUTIVE PAYROLL	89,119	87,540	(2)%	82,699	(8)%
204,458	216,936	6 %	201,234	(2)%	EXEMPT PAYROLL	2,402,435	2,581,976	7 %	2,441,209	2 %
509,144	539,440	6 %	511,585	0 %	OPERATING PAYROLL	6,480,974	6,473,346	0 %	6,135,956	(6)%
267,054	167,969	(59)%	232,623	(15)%	EMPLOYEE BENEFITS	2,774,170	2,011,423	(38)%	2,021,125	(37)%
988,208	931,640	(6)%	952,435	(4)%	TOTAL COMPANY LABOR	11,746,698	11,154,285	(5)%	10,680,989	(10)%
42,141	24,022	(75)%	11,346	(271)%	MATERIALS & SUPPLIES	434,212	290,577	(49)%	251,316	(73)%
3,530	90,123	96 %	51,901	93 %	TRANSPORTATION	728,547	1,081,338	33 %	927,045	21 %
					OTHER:					
130,898	135,776	4 %	168,428	22 %	DEPARTMENTAL SPECIFIC	1,374,085	1,634,617	16 %	1,630,605	16 %
29,241	33,458	13 %	0	100 %	ADMINISTRATIVE	299,587	422,408	29 %	0	100 %
6,100	17	(5782)%	0	100 %	OUTSIDE SERVICES	228,265	200	(4033)%	15	(1667)%
15,398	23,020	33 %	18,701	18 %	OTHER DEPARTMENT DIRE	168,911	277,855	39 %	234,348	28 %
57,126	50,859	(12)%	8,577	(566)%	ALLOCATIONS & OTHER	417,089	729,967	43 %	380,548	(10)%
238,763	243,130	2 %	195,706	(22)%	TOTAL OTHER	2,487,937	3,065,047	19 %	2,245,516	(11)%
1,272,642	1,288,915	1 %	1,211,388	(5)%	TOTAL INCURRED COST	15,397,394	15,591,247	1 %	14,104,866	(9)%
0	62	100 %	0	100 %	ALLOCATIONS - OUT	0	755	100 %	1,685	100 %
166,279	(86,915)	(291)%	(58,009)	(386)%	REVENUE/REIMBURSEMENTS	346,977	235,471	(47)%	208,370	(67)%
1,438,921	1,202,062	(20)%	1,153,379	(25)%	TOTAL NET EXPENSES	15,744,371	15,827,473	1 %	14,314,921	(10)%

LAST PAGE OF REPORT

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/94

REF: RESP-30
ISSUED 09/05/95

CO DIV W

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	NARUC	ACCOUNT	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
0	0	0 %	717	MFG GAS PROD-OPT-LIQ PETRO GAS	0	223	100 %
0	0	0 %	723	MFG GAS PROD-OPT-FUEL-L/P GAS	1,826	101	(1708)%
6,549	12	(4475)%	735	MFG GAS PROD-OPT-MISC PROD EXP	6,756	390	(1632)%
0	0	0 %	752	NG PROD-OPT-GAS WELLS EXP	69	373	82 %
140	171	18 %	756	NG PROD-OPT-FIELD MEAS & REG	1,717	942	(82)%
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
16	71	77 %	766	NG PROD-MAINT-FIELD MEAS & REG	1,777	1,329	(34)%
84	0	(100)%	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,042	877	(19)%
1,599	2,442	35 %	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	29,345	56,579	48 %
1,163	960	(21)%	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	12,261	10,924	(12)%
2,855	4,607	38 %	816	NG STORG-UNDRGRND-OPT-WELLS EXP	64,335	43,237	(49)%
1,886	930	(103)%	817	NG STORG-UNDRGRND-OPT-LINES EXP	33,765	26,377	(28)%
4,165	4,232	2 %	818	NG STORG-UNDRGRND-OPT-COMP EXP	76,806	56,272	(36)%
6,045	5,441	(11)%	819	NG STORG-UNDRGRND-OPT-COMP PWR	35,622	40,576	12 %
1,249	1,458	14 %	820	NG STORG-UNDRGRND-OPT-MEAS REG	30,803	24,706	(25)%
1,376	1,951	29 %	821	NG STORG-UNDRGRND-OPT-PURIF EXP	29,863	28,448	(5)%
377	532	29 %	824	NG STORG-UNDRGRND-OPT-OTHER EXP	6,391	6,338	(1)%
1,802	1,902	5 %	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	39,235	35,729	(10)%
1,297	1,395	7 %	826	NG STORG-UNDRGRND-OPT-RENTS	15,560	15,840	2 %
58	258	78 %	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	942	321	(193)%
48	160	70 %	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	3,892	870	(347)%
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	43	436	90 %
214	0	(100)%	834	NG STORG-UNDRGRND-MAINT COMP STN	7,455	10,856	31 %
401	1,435	72 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	4,699	6,140	23 %
0	15	100 %	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	1,266	2,560	51 %
1,464	1,588	8 %	850	TRANS-OPT-SUPRV & ENGINEERING	17,499	19,198	9 %
32,696	31,507	(4)%	856	TRANS-OPT MAINS EXPENSES	242,789	254,101	4 %
6,606	10,297	36 %	857	TRANS-OPT MEA & REG STAT EXP	136,858	155,370	12 %
2	0	(100)%	859	TRANS-OPT-OTHER EXPENSES	2	0	(100)%
0	600	100 %	860	TRANS-OPT-RENTS	512	1,850	72 %
0	15	100 %	862	TRANS-MAINT-STRUCT & IMPROVMENTS	1,615	3,043	47 %
912	2,532	64 %	863	TRANS-MAINT-MAINT OF MAINS	8,048	8,575	6 %
1,969	1,389	(42)%	865	TRANS-MAINT-MEAS & REG STATN EQUIP	40,029	41,575	4 %
131,767	118,152	(12)%	870	DISTRIB-OPT-SUPRV & ENGINEERING	1,520,984	1,383,310	(10)%
31,382	24,940	(26)%	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	399,116	388,548	(3)%
0	0	0 %	872	DISTRIB-OPT-COMP STAT LABOR & EXPENSE	46	0	(100)%
62,485	80,765	23 %	874	DISTRIB-OPT-MAINS & SERVICES	1,139,060	986,643	(15)%
11,319	8,657	(31)%	875	DISTRIB-OPT-MEAS & REG STAT-GEN	60,067	47,936	(25)%
23,052	21,828	(6)%	876	DISTRIB-OPT-MEAS & REG STAT-IND	275,252	278,563	1 %
13,478	9,717	(39)%	877	DISTRIB-OPT-MEAS & REG CITY GATE	166,365	141,762	(17)%
88,520	86,993	(2)%	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,159,170	1,035,943	(12)%
63,342	73,433	14 %	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	755,500	783,919	4 %
10,144	41,409	76 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	90,519	337,628	73 %
101,497	65,313	(55)%	881	DISTRIB-OPT-RENTS/BLDG SRV	1,109,810	740,248	(50)%
36,876	38,677	5 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	473,380	450,148	(5)%
7,411	9,680	23 %	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	25,797	33,915	24 %
(14,974)	13,941	207 %	887	DISTRIB-MAINT-MAINT OF MAINS	136,945	189,004	28 %
3,422	5,411	37 %	889	DISTRIB-MEAS & REG STAT - GEN	22,663	23,141	2 %

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/94

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV(UNFAV) COMPARED TO LST YR	ACCOUNT	DESCRIPTION	YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV(UNFAV) COMPARED TO LST YR
6,433	4,608	(40)%	890	DISTRIB-MEAS & REG STAT - IND	61,092	73,883	17 %
2,922	4,275	32 %	891	DISTRIB-MEAS & REG STAT - CITY GATE	44,070	49,017	10 %
2,998	5,771	48 %	892	DISTRIB-MAINT OF SERVICE	73,521	78,755	7 %
5,395	2,781	(94)%	893	DISTRIB-MTRS & HOUSE REG	55,854	44,022	(27)%
1,622	779	(108)%	894	DISTRIB-MAINT-OTHER EQUIPMENT	14,259	24,761	42 %
31,692	19,417	(63)%	901	CUS ACT EX-OPT-SUPERVISION	271,469	258,681	(5)%
65,194	71,667	9 %	902	CUS ACT EX-OPT-METER READING EXP	951,110	960,999	1 %
148,964	139,514	(7)%	903	CUS ACT EX-OPT-CUS REC/COLL EXP	1,914,821	1,776,833	(8)%
159,084	(66,774)	(338)%	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	436,574	235,374	(85)%
11,417	11,864	4 %	909	CUS SRV EXP-OPT-SUPERVISION	125,559	161,106	22 %
29,393	24,028	(22)%	910	CUS SRV EXP-OPT-CUSTMR ASSIST	322,541	324,007	0 %
2,978	(3,488)	(185)%	911	CUST SRV EXP-OPT-INFRM ADV EXP	18,993	94,304	80 %
861	1,199	28 %	915	SALE PROMO EXP-OPT-SUPERVISION	12,903	16,514	22 %
56,153	8,302	(576)%	916	SALE PROMO EXP-OPT-DEMO & SELL	411,331	268,936	(53)%
265	1,856	86 %	917	SALE PROMO EXP-OPT-PROMO ADV	2,644	5,753	54 %
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	4,598	4,858	5 %
39	2,801	99 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	1,181	10,994	89 %
5,000	0	(100)%	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	10,024	0	(100)%
(2,627)	6,942	138 %	925	A&G EX-OPT INJR&DAMG INS DR/CR	197,160	95,314	(107)%
270,227	231,030	(17)%	926	A&G EX-OPT-EMP WELF/PENS DR/CR	2,689,143	2,039,125	(32)%
0	670	100 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	10,078	9,407	(7)%
0	9,538	100 %	928	A&G EX-OPT-REGULATORY COMM EXP	0	114,453	100 %
(4,982)	0	100 %	929	A&G EX-OPT DUPLICATE CHRGS - CR	(103,413)	(35,871)	188 %
1,200	1,785	33 %	9302	A&G EX-OPT-MISC GENERAL EXP	31,265	28,735	(9)%
1,438,922	1,153,381	(25)%		TOTAL NET EXPENSES	15,744,373	14,314,924	(10)%

LAST PAGE OF REPORT

69

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69 a
Witness: Betty L. Adams

Data Request:

On page 8, line 22 of Ms. Adams' testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and ...a four percent wage increase."

a. Provide the number of vacant employee positions, by job classification, that Western intends to fill.

Response:

Please see attached Schedule A.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69-A

JOB VACANCY SUMMARY

No. of Vacancies	Position	Location
1	Sr. Engineer	Engineering & Measurement
1	Service Specialist	Hopkinsville C&M/Service
1	Sr. Service Tech	Hopkinsville C&M/Service
1	Operations Supervisor	Bowling Green C&M/Service
1	Service Specialist	Bowling Green C&M/Service
1	Sr. Construction Operator	Bowling Green C&M/Service
1	Meter Reader	Glasgow C&M/Service
1	Sr. Construction Operator	Danville C&M/Service
1	Sr. Service Tech	Campbellsville C&M/Service
1	Sales Representative II	Paducah C&M/Service
2	Sr. Service Tech	Paducah C&M/Service
1	Crew Foreman	Paducah C&M/Service
2	Sr. Construction Operator	Paducah C&M/Service
15	Total Vacancies - Western Kentucky Gas Company	

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69 b
Witness: Betty L. Adams

Data Request:

On page 8, line 22 of Ms. Adams' testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and …a four percent wage increase."

b. Provide the actual employee positions, by job classification, and provide the actual period used to determine the number of vacant positions necessary.

Response:

Please see attached Schedule B.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69-B

Job Title	No. of Positions
Computer Mapping Technician	3
Construction Operator	13
Corrosion Control Coordinator	1
Corrosion Control Technician	6
Crew Foreman	24
Emp Development & Safety Coordinator	2
Engineering Technician	5
Executive Assistant	1
Field Operator	8
Field Support Analyst	2
Financial Analyst	1
Laborer	2
Large Volume Sales Engineer	1
Manager Engineering Services	2
Manager Information Services	1
Manager Public Affairs	1
Manager Sales	1
Measurement Specialist	2
Measurement Supervisor	1
Meter Reader	10
Operations Assistant	21
Operations Manager	5
Operations Specialist	12
Operations Supervisor	15
President	1
Sales Representative I	2
Sales Representative II	5
Service Specialist	13
Service Technician	11
Sr. Administrative Assistant	4
Sr. Construction Operator	24
Sr. Engineer	1
Sr. Service Technician	55
Storage Foreman	2

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69-B

Job Title	No. of Positions
Storage Technician	2
Town Operator	9
VP & Controller	1
VP Eastern Region	1
VP Human Resources	1
VP Marketing	1
VP Rates & Regulatory Affairs	1
VP Technical Services	1
VP Western Region	1
Warehouse Coordinator	1
Warehouse Technician	5
Total WKG Employees	282

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item (69 c)
Witness: Betty Adams

Data Request:

On page 8, line 22 of Ms. Adams testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and...a four percent wage increase."

c. Does Western have both union and non-union employees? If there are union employees, provide the job classifications and a copy of the union contract.

Response:

c. Western does not have a union contract. The last contract ended when employees located in Paducah, Kentucky voted to decertify their union in 1992.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item (69 d)
Witness: Betty Adams

Data Request:

On page 8, line 22 of Ms. Adams testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and...a four percent wage increase."

d. Provide a schedule showing the derivation of the proposed 4 percent wage increase along with an explanation of how wage increases are determined for management, union and non-union employees.

Response:

d. WKG's base wage program as described in the attached documents applies to management, exempt and non-exempt employees. There are no union employees.

Pay philosophy and strategy is communicated to all employees in the attachment "Your Base Pay Opportunities at Atmos". The methodology of establishing pay ranges is in the attachment "Job Assignments".

The guidelines for pay delivery and basis for FY salary budgets are in the attachment "Atmos Energy Corporation FY '99 Pay Guidelines".

Rewards clearly aligned with the Company's vision and strategy

Your Base Pay Opportunities at Atmos

Atmos' Base Pay Program is designed to be flexible and responsive to the organizational growth and changes we have experienced -- and fully expect to continue -- in the years ahead.

The new pay program looks externally at jobs and is driven by what the "market" -- other companies -- pays for a job skill. It will provide base pay opportunities within a specific, competitive market range based on performance, experience, skills and responsibilities.

In addition, we have created the Variable Pay Plan (see page 6) that specifically was designed to offer you the opportunity to share in the successes you and your team help create by meeting corporate and team performance goals.

More Flexibility

There are a couple of important changes from past programs:

- Jobs with similar market values are now grouped into broad pay grades based on "market pricing," and
- Jobs are no longer evaluated using the Hay system or any other point-factor system.

"Market pricing" is determined using well-known, national surveys containing information on "benchmark" jobs. The surveys used with our program consider companies similar to Atmos in overall size in the gas industry as well as in general industry. A promotion to the next higher level pay grade is appropriate when:

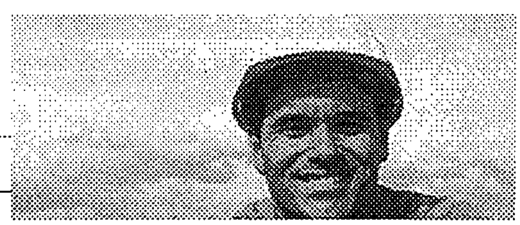
As part of the shift to a purely market-driven strategy, the Base Pay Program will change from many different pay ranges to eight broad pay grades.

Why broad pay grades? It's a better approach for both you and Atmos because broad pay grades:

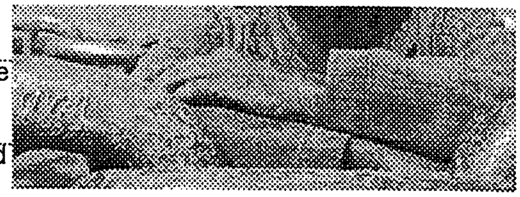
- Better reflect broader, more fluid jobs and roles
- Provide a more flexible means to pay employees according to their responsibilities, skills, experience and performance, and
- Allow us to respond more quickly to changes in our industry.

What's Different -- At a Glance

	Former Program	New Program
Number of pay ranges/grades	Dozens of ranges	8 broad pay grades
Salary increase	Very Structured	Flexible, reflect



	Very Structured	
guidelines		performance, experience and skills
Use of market pricing	One piece of information used to develop structure	Drives overall structure and is used to make pay decisions
Role of your manager/ supervisor	Administers guidelines	Manages your pay and career development



Job assignments

ATMOS

Atmos jobs were assigned to the proposed eight band structure using two methodologies:

Market Pricing

Whole Job Slotting

Market pricing

Objective

- ❑ Determine competitive market pay rates for as many benchmark positions as possible

Process

- ❑ Selected benchmark jobs for market pricing; guidelines used in selection included:
  - ❖ jobs that are common to other organizations
  - ❖ jobs that cover a number of incumbents
  - ❖ jobs that represent all job families and areas within the organization

- ❑ Determined appropriate survey sources to use in market pricing; criteria for survey selection included:
  - ❖ survey publisher is a reputable third-party, known for collecting, verifying and reporting data according to standard survey practices
  - ❖ survey has been conducted for a number of years
  - ❖ survey includes a sufficiently large participation base
    - ➜ for industry surveys, participants include those that Atmos might compete with for talent
    - ➜ for general industry surveys, participants represent a good cross-section of industries

- ❑ Verified target market to be the median or 50th percentile of the market

Market pricing

ATMOS

Process (continued)

- ❑ Set an effective date for all data at October 1, 1998 - date of program implementation

- ❑ Matched benchmark job descriptions to "good matches" in published salary surveys

  - ❖ a "good match" is defined as one where 70% to 80% or more of the types and levels of duties and responsibilities of the position are similar

- ❑ Using selected published salary surveys and position matches, gathered market pay data from survey sources; combined survey data to determine the market 50th percentile base pay rate

- ❑ Using the market 50th percentile base pay rate for each benchmark job, assigned jobs to the new salary structure

<u>Note:</u> Our focus throughout this process was on determining market rates for jobs, not individual incumbents

Whole job slotting

Objective

- ❑ Determine the appropriate band assignment for non-benchmark jobs (note: a "non-benchmark job" is defined here as a job which has not been assigned to a band based on market data)

Process

- ❑ Gathered appropriate reference materials
  - ❖ salary structure - all bands and salary ranges to which jobs would be assigned
  - ❖ band assignments for jobs that had been priced in the market place
  - ❖ list of all non-benchmark jobs (those needing slotting)
  - ❖ any other information that was useful in making job slotting decisions such as any available job documentation, organization charts, etc.
- ❑ Using the reference materials and the considerations outlined on the following page, we went through each non-benchmark job and made a decision regarding where the job should be slotted

  Note: As with the market pricing activities, we evaluated and slotted jobs, not incumbents

Whole job slotting

Considerations

- ❑ Where peer jobs were located/banded (peers in the same job family and across job families)
  - ❖ for example, if the non-benchmark job was considered a peer of a benchmark job already assigned to a band based on market data, we may have assigned the non-benchmark job to the same band as that of the peer job
- ❑ Steps in career ladders
  - ❖ for example, we may have been able to price an intermediate level for a job, but not the entry or senior level; in such a situation, the non-benchmark levels may have been slotted based on their relationship to the benchmark job
- ❑ Sources/Uses of incumbents
  - ❖ for example, if we knew the job and band from which incumbents are typically promoted into the non-benchmark job, and we knew the job and band into which incumbents go when they are promoted from the non-benchmark job, we could slot the non-benchmark job somewhere in between
- ❑ Any relevant/related market data
  - ❖ for example, if the non-benchmark job was a combination of two jobs we were able to price in the market place, the non-benchmark job may have been assigned to the same band or a band slightly higher than the jobs we were able to price; the decision to assign the non-benchmark job to a higher band level would depend on how much of a premium we believe the job should receive for performing combined duties of the benchmark jobs

Atmos Energy Corporation
FY 1999 Pay Guidelines

General Salary Increase Information:

- Salary increases across the country are forecast to continue between 4.0 and 4.5 percent. The table below reflects actual experience for 1997 and 1998 and what is projected for 1999. The amounts shown include general cost-of-living adjustments, merit increases and other adjustments such as market or equity-related increases. Promotions are excluded from these salary increase amounts. Additionally, according to the Bureau of Labor Statistics, the rate of inflation from June 1997 through June 1998 was 1.7 percent.

Employee Category	Actual 1997	Projected 1998	Actual 1998	Projected 1999
Operating Nonexempt Employees	**4.1%**	**4.2%**	**4.2%**	**4.3%**
Exempt Salaried Employees	**4.3%**	**4.3%**	**4.5%**	**4.4%**

Merit Increase Guidelines

- **Form -** During the transition to the new performance management system, the current performance appraisal form will be used on which to partially base an employee's FY 99 merit salary increase until we introduce the enhanced process on or about April 1, 1999.

- **Merit Increase Considerations**

  - The following table provides guidelines to assist you in determining an employee's merit increase amount as a percentage of pay based on your evaluation of his/her performance.

  - In addition to an employee's performance rating, consideration should also be given to the employee's position within the new pay band.

Performance Rating	Recommended FY 99 Salary Increase Range
1	0% to 8%
2	0% to 6%
3	0% to 4%
4	0% to 1%
5	0%

- The following specific considerations have been developed to assist supervisors/managers in the application of both merit increases and the transition to the company's new broad band base pay practice within the labor dollars that have been budgeted. Considerations are listed in priority order.

  - **Employees whose pay is below the new band minimum** – immediately consider granting a pay adjustment to bring the employee's base pay to the pay band minimum or develop a plan of action that provides up to two pay adjustments to bring the employee's base pay to the pay band minimum by no later than September 30, 1999.

    Example:

    Situation - A new employee who is being paid $18,000 on an annual basis and is in a job with a band minimum of $20,500.

    Action - You may immediately authorize a pay adjustment of $2,500 ($96 bi-weekly) or you may grant two increases of $1,250 ($48 bi-weekly) each over the next 12 months to bring this employee's pay to band minimum.

  - **Employees whose pay falls in the Value Pay or the higher end of the Target Pay segment, but whose performance does not warrant this pay level** - provide a lesser merit increase than you normally would provide based on the guidelines above.

    Example:

    Situation - An employee with long tenure but whose performance is average is being paid $39,000 annually and is in a job with a Value Pay segment range of between $36,000 and $41,000.

    Action - Instead of providing this employee a merit increase of 4% according to the guidelines above, consider granting a merit increase in the range of 2% to 3%.

  - **Employees whose pay falls in the Entry or Target Pay segments but whose performance warrants Target or Value pay respectively** - apply a greater merit increase than you normally would to move or start moving the employee's pay to higher and more appropriate levels within pay band.

Example:

Situation - An employee who is one of your best performers is being paid $32,000 annually and is in a job where the Value Pay segment ranges from $36,000 to $41,000.
Action - Instead of granting this employee a merit increase of 6% according to the guidelines above, consider granting a merit increase in the range of 7% to 8%.

- **Employees whose pay are close to or exceed the band maximum -** consider granting a lump sum merit award. The amount of such lump sum award should be based on the employee's performance but no more than the average merit increase budget of 4%.

Example:

Situation - An employee who is a good solid performer is being paid $35,000 annually and is in a job where the band maximum is $33,000.
Action – You should not adjust the employee's base pay as he/she is already paid in excess of the band maximum. You should consider granting a lump sum merit award of $350 - $700, or 1% - 2% of base pay. ($35,000 x 1% - 2%)

- **Your supervisor/manager must approve any pay increase that exceeds these guidelines.**

- An employee's pay may not be increased more than two times or a total of 20% in any fiscal year. If you feel that an exception should be made to these guidelines, please obtain approval from your respective BU President or Corporate VP prior to executing any pay action that exceeds these guidelines.

Executing a Pay Increase

- Merit Increase

  - Compute the actual dollar amount of the employee's salary increase in whole dollars based on the company's bi-weekly payroll schedule and forward this information to BU/Shared Services HR for entry into payroll. The payroll action form is to be used for this purpose.

  - For example, if an employee's merit increase is $2,500 on an annual basis, divide $2,500 by 26 pay periods to authorize a merit increase of $96 on each bi-weekly paycheck.

- Below Band Minimum Increase

  - Compute the actual dollar amount of the employee's salary increase to bring the employee's salary to the band minimum and record this amount on the Transitional Pay Adjustment Request along with your rationale for such request. Forward the completed Transitional Pay Adjustment Request to your BU President or Corporate VP, as appropriate, for approval and forwarding to Dallas HR.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69 e
Witness: Betty L. Adams

Data Request:

On page 8, line 22 of Ms. Adams' testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and …a four percent wage increase."

e. Provide a list of the planned positions being filled that were previously held by contractors, by job classification, and break down the list further by identifying contractors performing construction activities, not operational duties.

Response:

None of our planned positions to be filled were previously held by contractors.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69 f
Witness: David H. Doggette

Data Request:
On page 8, line 22 of Ms. Adams' testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and... a four percent wage increase."

f. Identify how many years the contractors have performed construction activities and whether these activities are now being considered in the planned construction budget.

Response:

Contractors have been utilized, for various projects, throughout Western's service territory dating back to the 1960's. Western does not separately budget for contract labor. At present, the use of contractors is not anticipated. The test year construction budget reflects total planned construction spending.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 69 g
Witness: Betty L. Adams

Data Request:

On page 8, line 22 of Ms. Adams' testimony there is a discussion of the increase in the forecasted test period labor costs that is attributed to "the planned filling of a number of vacant employee positions and ...a four percent wage increase."

g. If the planned positions are replacing contractors that have been performing construction services, and construction services with contractors are included in the planned construction budget, provide a detail description of the expected benefits from the addition of the planned operating and maintenance employees that Western's customers will receive that they have not been receiving.

Response:

None of our planned positions to be filled were previously held by contractors.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 70
Witness: Betty L. Adams

Data Request:

Resubmit Volume 3 (question reference to Volume 9 in error), FR 10(h)9 for the years 2000 through 2003 with employees separated by job classifications. Also, provide a comparison of budgeted to actual numbers of employees for FY 1994 through 1998. Provide references in each of these schedules to the employee numbers by Western's chart of account number, NARUC account, and FERC account. Explain any increases or decreases of 5 percent or more in employee numbers from year to year.

Response:

Please see DR 69 b, Schedule B for the employees separated by job classifications.

Attached is a schedule showing the comparison of authorized to actual employees for the FY 1994 through 1998. All of the authorized positions were not budgeted for all years. Our authorized positions were reduced starting in FY 97 due to the beginning of implementation of various service improvements as discussed in Mr. Gruber's Testimony.

We do not budget employees by NARUC or FERC accounts as most perform multiple functions.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 70

Year	No. Authorized	No. Employees
1994	404	387
1995	405	383
1996	393	373
1997	283	329
1998	283	267

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 71
Witness: Betty Adams

Data Request:

On page 9, lines 10 through 17 of Ms. Adams' testimony is a discussion of the increase in the forecasted test period communications expense that is attributed to increased use of mobile data terminals (MDT's) and higher cellular usage. Provide a schedule showing the cost amounts, MDT units acquired and plant accounts charged since the project inception, showing the years in which the investments in MDT's were made.

a. Does Western have contracts for communications expenses, such as long distance and cellular usage?

Response:

Yes. Western does have contracts for cellular service. These cellular contracts, as with most large business cellular contracts, are for the cellular line(s), i.e. the telephone number. Usage and long distance are an additional charge. Western's cellular usage and long distance has increased and is anticipated to increase in the forecasted year. The increase is primarily due to two effects. First, the growing direct contact between the customer and the technician that cellular phones afford. Second the installation of the mobile data terminals and their cellular modems have impacted cellular usage. Additionally, Western has seen a significant increase in technician calls to the Customer Support Center.

b. If yes, provide the old and new contracts and an explanation of why the usage was deemed to increase in the forecasted period considering any contractual changes or changes in services used.

Response:

Attached is a copy of a master contract with BellSouth as an example. Western has approximately twenty (20) similar contracts in place in order to provide adequate cellular coverage of our service territory. Please see the above response regarding increased cellular usage.

c. Give a quantified determination of how this increase was estimated and weather the costs are under contract or not.

Response:

Annual cellular costs for the base period year are $79,140. The cellular costs for the forecasted year are expected to be $126,168.

Credit Reference Number

❑ ESN Change ❑ No Install ❑ Conversion

98767276 Mobile Number

Date

1) Mobile # (______) ______ E.S.N. ______

2) Mobile # (______) ______ E.S.N. ______

3) Mobile # (______) ______ E.S.N. ______

4) Mobile # (______) ______ E.S.N. ______

See Addendum

CONSUMER – *Complete Boxes 1 & 3* **COMMERCIAL/CORPORATE** – *Complete Boxes 1, 2, & 3*

Market: Obown Agent Code Sales Rep.: 120153 Yes X No ____ Existing customer?

BELLSOUTH Mobility

CREDIT APPLICATION

1 CONSUMER –

Print the name and address of person responsible for charges made to this account:

Responsible Party First Name: Western Ky Gas MI Last Name

Billing Address/Post Office Box: 2401 New Hartford Rd

City: Owensboro State: Ky Zip + Four: 42303-1312

Home Phone: ( ) Work Phone: (502) 685 8100

Social Security Number

Date of Birth ___/___/___ Male Female

Driver's License Number State

ANNUAL INCOME

- ❑ UNDER $35,000
- ❑ $36,000 - $49,999
- ❑ $50,000 - $74,999
- ❑ $75,000 - $89,999
- ❑ $90,000 - $105,999
- ❑ $106,000 - $114,999
- ❑ $115,000 & ABOVE

2 COMMERCIAL/CORPORATE –

Up to 48-hour processing time

Company Name Purchase Order Number

Tax Exempt Number

Supervisor's Name Supervisor's Phone No. ( ) Yrs. In Business

Does street address differ from billing address? Yes ____ No ✓

Is this branch or subsidiary of the main office? Yes ____ No ✓

Type of business: ❑ Corporation ❑ Sole Proprietorship or Partnership ❑ Other

Bank Name	Account Officer	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number

IDENTIFICATION

3 ATTACH COPY OF DRIVER'S LICENSE OR PICTURE I.D.

This is to certify that I have positively identified the above applicant's name and signature and that it matched the signature and name on this BellSouth Mobility Cellular Agreement.

Name of Company: BMT

Sales Representative's Signature

Date: 4/29/99

Print Name: Chef Hopewell

SERVICE APPLICATION

SERVICE PLAN SELECTED: Multi line 10K $1600.00

Local airtime minutes included per month: Digital Add 15.00 ea

CUSTOM CALLING FEATURES Analog Add 20.00 ea

- ❑ Call Waiting
- ❑ Call Forwarding
- ❑ No Answer Transfer Overage .18¢ min
- ❑ Three Party Conferencing $____
- ❑ Any Two Features $____
- ❑ Any Three Features $____ $____.____

OTHER

- ❑ Mobile Memo $____
  - Description ____
  - Pager # ____
- ❑ PowerCall One-Number Service $____
  - Description ____
- ❑ Nights & Weekends $____
- ❑ Mobile-To-Mobile $____
- ❑ Emergency Road Service* $____
- ❑ Detailed Billing $____
- ❑ Toll Restricted $____
- ❑ Incoming Calls Only $____
- ❑ Outgoing Calls Only $____
- ❑ Miscellaneous ____ $____
- ❑ Miscellaneous ____ $____ $____.____

EQUIPMENT INSURANCE

Signal Dial Direct Plus* *(initial one)* Accept ____ Decline ____

(Not available in all locations)

	Monthly Premium	Loss/Damage Deductible	Mech/Elect Deductible
❑ Mobiles	$ 2.95	$ 0	$ 25
❑ Portables/Transportables	$ 2.95	$ 35	$ 25
❑ Accessories	$ 1.95	$ 35	$ 25

$____.____

*If you subscribe to cellular phone insurance and/or emergency road service, you acknowledge that you have received and read the brochure for same and understand the terms and conditions under which same is offered outlined therein.

I understand that in the event of a loss, theft or damage, replacement of my cellular phone may be greater than the original price. ________ (Customer Initials)

TOTAL MONTHLY SERVICE

(Excluding additional airtime charges and taxes) $____.____

LONG DISTANCE

- ❑ BellSouth Long Distance
- ❑ Other ____

INFORMATION

LN TY	QTY	ITEM NUMBER (Required)	DESCRIPTION	SERIAL NUMBERS	NET UNIT PRICE
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$

❑ Paid with Order ❑ Check/Cash Receipt # ____ Sales/Install Branch ____ Non-Taxable Subtotal $

❑ Invoice Customer Net 30 P.O. # ____ Inventory Branch ____

❑ Credit Card ❑ MC ❑ Visa ❑ AMEX ❑ Other ____ Card # ____ Taxable Subtotal

CREDIT APPLICATION

2401 New Hartford Rd
Billing Address/Post Office Box ... Last Name

Owensboro Ky 42303-1312
City State Zip + Four

( )
Home Phone

(502) 685 8100
Work Phone

Social Security Number

Date of Birth Male Female

Driver's License Number State

ANNUAL INCOME
- ☐ UNDER $35,000
- ☐ $35,000 - $49,999
- ☐ $50,000 - $74,999
- ☐ $75,000 - $89,999
- ☐ $90,000 - $105,999
- ☐ $106,000 - $114,999
- ☐ $115,000 & ABOVE

2 COMMERCIAL/CORPORATE -
Up to 48-hour processing time

Purchase Order Number

Company Name Tax Exempt Number

( )
Supervisor's Name Supervisor's Phone No. Yrs. In Business

Does street address differ from billing address? Yes____ No ✓
Is this branch or subsidiary of the main office? Yes____ No____
Type of business: ☐ Corporation ☐ Sole Proprietorship or Partnership ☐ Other

Bank Name	Account Officer	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number
Trade Reference	Contact	Phone Number	Account Number

IDENTIFICATION

3 ATTACH COPY OF DRIVER'S LICENSE OR PICTURE I.D.
This is to certify that I have positively identified the above applicant's name and signature and that it matched the signature and name on this BellSouth Mobility Cellular Agreement.

BMT
Name of Company Sales Representative's Signature

4/29/99 Chet Hopewell
Date Print Name

SERVICE APPLICATION

Analog Add 20.00 84
Overcase .18 ct min

CUSTOM CALLING FEATURES
- ☐ Call Waiting
- ☐ Call Forwarding
- ☐ No Answer Transfer
- ☐ Three Party Conferencing $____
- ☐ Any Two Features $____
- ☐ Any Three Features $____ $____

OTHER
- ☐ Mobile Memo $____
  - Description ____
  - Pager # ____
- ☐ PowerCall One-Number Service $____
  - Description ____
- ☐ Nights & Weekends $____
- ☐ Mobile-To-Mobile $____
- ☐ Emergency Road Service* $____
- ☐ Detailed Billing $____
- ☐ Toll Restricted $____
- ☐ Incoming Calls Only $____
- ☐ Outgoing Calls Only $____
- ☐ Miscellaneous ____ $____
- ☐ Miscellaneous ____ $____ $____

EQUIPMENT INSURANCE
Signal Dial Direct Plus® *(initial one)* Accept ____ Decline ____
(Not available in all locations)

	Monthly Premium	Loss/Damage Deductible	Mech/Elect Deductible
☐ Mobiles	$ 2.95	$ 0	$ 25
☐ Portables/Transportables	$ 2.95	$ 35	$ 25
☐ Accessories	$ 1.95	$ 35	$ 25

$____

*If you subscribe to cellular phone insurance and/or emergency road service, you acknowledge that you have received and read the brochure for same and understand the terms and conditions under which same is offered outlined therein.

I understand that in the event of a loss, theft or damage, replacement of my cellular phone may be greater than the original price. ____ (Customer Initials)

TOTAL MONTHLY SERVICE
(Excluding additional airtime charges and taxes) $____

LONG DISTANCE
- ☐ BellSouth Long Distance
- ☐ Other ____

EQUIPMENT INFORMATION

LN TY	QTY	ITEM NUMBER *(Required)*	DESCRIPTION	SERIAL NUMBERS	NET UNIT PRICE
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$
				MSN / ESN	$

☐ Paid with Order ☐ Check/Cash Receipt # ____ Sales/Install Branch ____ Non-Taxable Subtotal $
☐ Invoice Customer Net 30 P.O. # ____ Inventory Branch ____ Taxable Subtotal $
☐ Credit Card ☐ MC ☐ Visa ☐ AMEX ☐ Other ____ Card # ____ Tax Rate %
Expiration ____ Authorization ____ Security Code ____ (If Applicable) Unlock Code ____

Bill with Service ____ *(Sales Director's Approval)* Order Total $
Balance $____ with ____ Monthly Payments of $____ ☐ Other: ____ (Customer's Initials) Down Payment $
Customer is purchasing equipment primarily for business purposes. Balance Due $

SCHEDULED INSTALLATION
___/___/___ ___:___ ☐ AM ☐ PM
Date Time
Make, Model & Color of Automobile
License Plate Number

ACKNOWLEDGEMENT

CUSTOMER ACKNOWLEDGEMENTS
- The monthly service charge and any minutes included will be prorated for the number of days in service during the first billing period.
- The first month's bill will show a monthly service charge for the following month, subsequently you will be billed one month in advance.
- All "Special Pricing Plans" are subject to eligibility requirements and approval. Ineligibility for "Special Pricing" does not nullify this agreement.
- When using your phone outside your home service area (roaming) rate may vary.
- Long distance is billed in addition to airtime.
- A connection charge of $ .24 per month will apply during any month in which a call originated from the cellular phone(s) is terminated through the landline network *(connection charge is subject to change on 30 days notice)*.
- The appropriate liquidated damages (up to $240.00) may apply for early cancellation *(see paragraph 18)*.
- Customer authorizes Company to check Customer's credit and to provide and exchange credit information regarding Customer with credit bureaus.
- Customer certifies that the pricing plan chosen has been explained and that the Customer understands the components of the pricing plan, including but not limited to the activation fee, monthly access charges, usage charges, liquidated damages, applicable taxes, rental agreements, where applicable) and agrees to same.

Customer elects to subscribe to BellSouth Mobility's * month agreement. ____ (Customer Initials)

By signing below, the undersigned "Customer" acknowledges the accuracy of the above information and has received a copy of, read, understands, and accepts the attached Terms and Conditions of Service Agreement (Form #BSCC 6-98).

Y

4/29/97

Customer Authorized Signature | Printed Name | Date | Deposit

WHITE - BMI YELLOW - SALES REP PINK - MOBILE EQUIPMENT SUPPLIER GOLD - CUSTOMER GOLD TERMS AND CONDITIONS - CUSTOMER

SERVICE AGREEMENT 8/98 BMI 190105

(*) See Addendum for Contract Dates

GREEMENT is entered into between the Carrier providing the service ("Company") and the user of the Service ("Customer") and is subject to acceptance by Company. Customer's acceptance is limited to the terms and conditions of this offer. No additions or subtractions by Customer ceptable unless and until expressly and mutually agreed upon.

PROVISION OF SERVICE.

(a) Company shall provide and Customer shall accept Service (all Services provided by Company are referred to herein as "Service") at the rates and charges shown on the signature slip included with this Agreement, for any lawful purpose, subject to the terms and conditions specified in this agreement. Company shall provide Customer with an access number by which Customer may use Company's system. Customer shall not have any proprietary right to the access number(s) provided to it by Company. Except as otherwise agreed by Company in writing, Company reserves the right to revise, in its sole discretion, the rates, terms, and conditions of its agreement with Customer upon at least 30 days written notice to Customer. Long distance rates for calls beyond Company's local service area are subject to change from time to time without notice. Customer agrees to pay for service pursuant to such revised rates, terms, and conditions, unless Customer terminates this agreement in accordance with the terms and conditions of this agreement. Company reserves the right to assign, designate or change access number(s) when, in its sole discretion, such assignment designation or change is reasonable or necessary in the conduct of its business.

(b) Service is subject to transmission limitations caused by atmospheric, topographical and any other like conditions. Additionally, Service may be temporarily refused, limited, interrupted or curtailed due to government regulations or orders, system capacity limitations, limitations imposed by an underlying carrier, or because of equipment modifications, upgrades, repairs or reallocations or other similar activities necessary or proper for the operation or improvement of Company's system. Certain services, such as directory listings, ...or services and roaming in some areas, may be provided by other carriers. Customer may use these services subject to the regulations and charges of such other carriers. Paging service is only available in conjunction with Company's wireless voice capable radio

(c) ...e to Customer may be refused, discontinued or terminated without written notice in the event the service is used by Customer in such a manner that will adversely affect the Company's service to any of its other customers, or if it is determined that the Customer's mobile radio unit is in violation of FCC rules or adversely affects the Company's service to any of its other customers.

DEPOSITS.

(a) Company may, from time to time, at its sole discretion and in order to safeguard its interest, require Customer to make suitable deposit(s) to be held by Company as a guarantee of the payment of charges. At such time as the relationship between Company and Customer is terminated, the amount of deposit, including any accrued interest required by law shall be credited to Customer's final bill and any remaining amount of deposit, after application to any amount due and owing by Customer to Company, will be refunded. Any credit balance, however, may be returned to Customer at any time prior to such termination, at the sole discretion of Company.

(b) Interest, will be paid on all sums retained on deposit by Company to the extent required by law. No refund of deposit, or interest accrued on such deposit, will be made until after such time as Customer has maintained the account in good standing for the lesser of 12 consecutive months or for the period required by law. No interest shall be paid on a deposit, or any portion of such deposit, after the day on which a refund is processed.

LIMITATION OF COMPANY'S LIABILITY.

(a) CUSTOMER UNDERSTANDS THAT ALTERNATIVE AND COMPETING COMMUNICATIONS CARRIERS ARE AVAILABLE TO CUSTOMER; INTERRUPTIONS OR IRREGULARITIES IN THE SERVICE MAY OCCUR; ANY POTENTIAL HARM FROM INTERRUPTIONS OR IRREGULARITIES IN THE SERVICE IS SPECULATIVE IN NATURE; COMPANY CANNOT OFFER THE SERVICE AT RATES WHICH REFLECT ITS VALUE TO EACH CUSTOMER; AND COMPANY ASSUMES NO RESPONSIBILITY OTHER THAN THAT CONTAINED IN THIS AGREEMENT. ACCORDINGLY, CUSTOMER AGREES THAT EXCEPT AS LIMITED BY LAW, COMPANY'S SOLE LIABILITY FOR LOSS OR DAMAGE ARISING OUT OF MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS, OR DEFECTS IN THE SERVICE OR TRANSMISSION OF SERVICE PROVIDED BY COMPANY OR ANY CARRIER, OR FOR LOSSES OR DAMAGES ARISING OUT OF THE FAILURE OF COMPANY OR ANY CARRIER TO MAINTAIN PROPER STANDARDS OF MAINTENANCE AND OPERATION SHALL BE AS FOLLOWS:

(i) A CREDIT ALLOWANCE, AS DESCRIBED IN SUB-SECTION 3 (a)(iii) BELOW, WILL BE MADE AT CUSTOMER'S REQUEST IN THE FORM OF A PRO-RATA ADJUSTMENT OF THE FIXED MONTHLY CHARGES BILLED TO CUSTOMER. FIXED MONTHLY CHARGES ARE THE MONTHLY CHARGES FOR ACCESS AND OPTIONAL FEATURES PER ACCESS NUMBER, ALL AS DESCRIBED IN THE SCHEDULE OF RATES AND CHARGES IN EFFECT AT THE TIME OF INTERRUPTION.

(ii) SUCH CREDIT ALLOWANCE WILL BE BASED UPON THE PERIOD OF TIME DURING WHICH SUCH MISTAKES, OMISSIONS, DELAYS, ERRORS OR DEFECTS IN THE SERVICE OR ITS TRANSMISSION CAUSED INTERRUPTIONS IN THE RENDERING OF THE SERVICE. ANY SUCH PERIOD OF TIME DURING WHICH AN INTERRUPTION OCCURS WILL BE MEASURED FROM THE TIME IT IS REPORTED TO OR DETECTED BY COMPANY, WHICHEVER OCCURS FIRST. IN THE EVENT CUSTOMER IS AFFECTED BY SUCH INTERRUPTION FOR A PERIOD OF LESS THAN 24 HOURS, NO SUCH ADJUSTMENT SHALL BE MADE. WHEN AN INTERRUPTION EXCEEDS 24 HOURS, THE LENGTH OF THE INTERRUPTION WILL BE MEASURED IN 24 HOUR DAYS. A FRACTION OF A DAY CONSISTING OF LESS THAN 12 HOURS WILL NOT BE CREDITED, BUT A PERIOD OF 12 HOURS OR MORE WILL BE CONSIDERED AN ADDITIONAL DAY.

(iii) THE CREDIT ALLOWANCE WILL BE COMPUTED BY DIVIDING THE LENGTH OF THE SERVICE INTERRUPTION BY A STANDARD 30 DAY MONTH AND THEN MULTIPLYING THE RESULT BY COMPANY'S FIXED MONTHLY CHARGES FOR EACH INTERRUPTED ACCESS NUMBER. IN NO CASE WILL THE CREDIT EXCEED THE FIXED MONTHLY CHARGES.

(iv) A CREDIT ALLOWANCE WILL NOT BE GIVEN FOR MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS OR DEFECTS, OR CURTAILMENTS IN THE SERVICE CAUSED BY THE NEGLIGENCE OR WILLFUL ACT OF CUSTOMER OR OTHER PARTIES, OR MISTAKES, OMISSIONS INTERRUPTIONS, DELAYS, ERRORS, OR DEFECTS CAUSED BY FAILURE OF EQUIPMENT OR SERVICE NOT PROVIDED BY COMPANY.

(v) THE SERVICE FURNISHED BY COMPANY, IN ADDITION TO THE LIMITATIONS SET FORTH PRECEDING, IS ALSO SUBJECT TO THE FOLLOWING LIMITATION: THE LIABILITY OF COMPANY FOR LOSS OR DAMAGES ARISING OUT OF MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS OR DEFECTS IN THE SERVICE, ITS TRANSMISSION OR FAILURES OR DEFECTS IN FACILITIES OF THE UNDERLYING CARRIER, OCCURRING IN THE COURSE OF FURNISHING SERVICE AND NOT CAUSED BY THE NEGLIGENCE OF THE AUTHORIZED USER, SHALL IN NO EVENT EXCEED AN AMOUNT EQUIVALENT TO THE PROPORTIONATE FIXED MONTHLY CHARGE TO THE CUSTOMER FOR SERVICE DURING THE PERIOD OF TIME IN WHICH SUCH MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS, OR DEFECTS IN SERVICE, ITS TRANSMISSION, OR FAILURES OR DEFECTS IN FACILITIES FURNISHED BY COMPANY OR THE UNDERLYING CARRIER OCCURRED.

(b) Company shall in no event be liable for service or equipment interruptions or delays in transmission, errors or defects in service or equipment, when caused by acts of God, fire, war, riots, government authorities, default of supplier, or other causes beyond Company's or any carrier's control.

(c) Customer acknowledges that Company's systems use radio channels to transmit voice and data communications and that the service may not be completely private. Company is not liable to customer for any claims, loss, damages or cost which may result from lack of privacy on the system.

(d) CUSTOMER HEREBY AGREES TO INDEMNIFY AND SAVE COMPANY HARMLESS AGAINST CLAIMS FOR LIBEL, SLANDER, OR INFRINGEMENT OR COPYRIGHT FROM THE TRANSMISSION OF MATERIAL IN ANY FORM OVER ITS FACILITIES BY CUSTOMER OR THOSE USING CUSTOMER'S EQUIPMENT; AGAINST CLAIMS FOR INFRINGEMENT OF PATENTS ARISING FROM COMBINING OR USING APPARATUS OR SYSTEMS OF CUSTOMER WITH THE FACILITIES OF COMPANY OR ANY CARRIER; AND AGAINST ALL OTHER CLAIMS ARISING OUT OF ANY ACT OR OMISSION OF CUSTOMER IN CONNECTION WITH THE FACILITIES OR SERVICE PROVIDED BY COMPANY.

(e) Company is not liable for any damage, accident, injury or the like occasioned by the use of Service or the presence of equipment, including cellular units and devices, facsimile units, pagers, and ancillary equipment of Customer or Company except as provided herein. Company is not liable for any defacement or damage to Customer's motor vehicle or any personal or real property resulting from the presence of radio and ancillary equipment.

(f) THE LIABILITY OF COMPANY IN CONNECTION WITH THE SERVICE PROVIDED IS SUBJECT TO THE FOREGOING LIMITATIONS AND COMPANY MAKES NO WARRANTIES OF ANY KIND, EXPRESSED OR IMPLIED, AS TO THE PROVISION OF SUCH SERVICE.

DISCLAIMER OF WARRANTIES AND LIMITATION OF REMEDIES.

(a) CUSTOMER ACKNOWLEDGES AND AGREES THAT COMPANY IS NOT THE MANUFACTURER OF EQUIPMENT AND COMPANY EXCEPT AS LIMITED BY LAW HEREBY DISCLAIMS ALL REPRESENTATIONS AND WARRANTIES, DIRECT OR INDIRECT, EXPRESS OR IMPLIED, WRITTEN OR ORAL, IN CONNECTION WITH THE EQUIPMENT OR SERVICE (WHETHER PURCHASED OR LEASED BY CUSTOMER FROM COMPANY OR ANOTHER), INCLUDING BUT NOT LIMITED TO ANY AND ALL EXPRESS AND IMPLIED WARRANTIES OF SUITABILITY, DURABILITY, MERCHANTABILITY, AND FITNESS FOR A PARTICULAR PURPOSE. COMPANY TO THE EXTENT PERMITTED BY LAW ASSIGNS TO CUSTOMER ANY AND ALL MANUFACTURERS' WARRANTIES RELATING TO EQUIPMENT PURCHASED BY CUSTOMER, AND CUSTOMER ACKNOWLEDGES RECEIPT OF ANY AND ALL SUCH ...CTURERS' WARRANTIES.

(b) ...R ACKNOWLEDGES AND AGREES THAT ITS SOLE AND EXCLUSIVE REMEDY IN CONNECTION WITH ANY DEFECTS IN THE EQUIPMENT, INCLUDING MANUFACTURE OR DESIGN, SHALL BE AGAINST THE MANUFACTURER OF THE EQUIPMENT UNDER THE MANUFACTURERS' ...TIES AND THAT COMPANY SHALL HAVE NO LIABILITY TO CUSTOMER IN ANY EVENT FOR ANY LOSS, DAMAGE, INJURY, OR EXPENSE OF ANY KIND OR NATURE RELATED DIRECTLY OR INDIRECTLY TO ANY EQUIPMENT OR SERVICE PROVIDED HEREUNDER. WITHOUT LIMITING THE ABOVE, COMPANY SHALL HAVE NO LIABILITY OR OBLIGATION TO CUSTOMER, IN EITHER CONTRACT OR TORT, FOR SPECIAL, INCIDENTAL, OR CONSEQUENTIAL DAMAGES OF ANY KIND INCURRED BY CUSTOMER, SUCH AS, BUT NOT LIMITED TO, CLAIMS OR DAMAGES FOR PERSONAL INJURY, WRONGFUL DEATH, LOSS OF USE, LOSS OF ANTICIPATED PROFITS, OR OTHER INCIDENTAL OR CONSEQUENTIAL DAMAGES OR ECONOMIC LOSSES OF ANY KIND INCURRED BY CUSTOMER DIRECTLY OR INDIRECTLY RESULTING FROM OR RELATED TO ANY EQUIPMENT OR SERVICE DESCRIBED HEREUNDER, WHETHER OR NOT CAUSED BY COMPANY'S NEGLIGENCE, TO THE FULL EXTENT SAME MAY BE DISCLAIMED BY LAW. ANY REFERENCES TO EQUIPMENT IN THIS PARAGRAPH SHALL BE DEEMED TO APPLY TO ALL EQUIPMENT PURCHASED BY CUSTOMER OR LEASED BY CUSTOMER FROM COMPANY OR ANOTHER LESSOR. SOME STATES DO NOT ALLOW THE EXCLUSION OR LIMITATION OF INCIDENTAL OR CONSEQUENTIAL DAMAGES SO THE ABOVE EXCLUSION MAY NOT APPLY. YOU MAY ALSO HAVE OTHER LEGAL RIGHTS WHICH VARY FROM STATE TO STATE.

INDEMNIFICATION AND RELEASE. CUSTOMER AGREES TO RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS COMPANY, ITS OFFICERS AND EMPLOYEES, TO THE FULL EXTENT PERMITTED BY LAW FROM AND AGAINST ANY AND ALL CLAIMS, DAMAGES, LIABILITIES AND EXPENSES, INCLUDING LEGAL AND ATTORNEY FEES, OF ANY NATURE ARISING DIRECTLY OR INDIRECTLY OUT OF THIS AGREEMENT, INCLUDING, WITHOUT LIMITATION, CLAIMS FOR PERSONAL INJURY OR WRONGFUL DEATH TO CUSTOMER OR USERS OF THE EQUIPMENT, PRODUCTS OR SERVICES PROVIDED BY COMPANY OR USED IN CONJUNCTION WITH SUCH EQUIPMENT, PRODUCTS OR SERVICES PROVIDED BY COMPANY AND ARISING OUT OF THE MANUFACTURE, PURCHASE, OPERATION, CONDITION, MAINTENANCE, INSTALLATION, RETURN OR USE OF THE EQUIPMENT OR SERVICE, OR ARISING BY OPERATION OF LAW, WHETHER THE CLAIM IS BASED IN WHOLE OR IN PART ON NEGLIGENT ACTS OR OMISSIONS OF COMPANY, ITS AGENTS OR EMPLOYEES.

RATES AND CHARGES. Unless otherwise agreed by Company, Customer will be billed in advance for monthly access charges and in arrears for usage charges. Usage of Service shall be measured in one minute increments and each partial minute shall be rounded up to the next ...minute increment. Customer will be charged a minimum of one minute for every call that is received or placed using Customer's equipment and sent or answered by the called party. Chargeable time is measured from time of channel seizure to channel termination. Company ...rves the right to define the hours of peak and off-peak, and nights and weekends calling times and Customer recognizes that scheduling of such times is subject to change and that such changes do not constitute changes in rates. Airtime rates do not include long distance ...rges for calls beyond Company's local service area.

PAYMENT OF CHARGES.

Unless otherwise agreed by Company, Payment is due to Company upon receipt of invoice by Customer. Service may be billed to Customer's credit card.

Customer shall be responsible for payment of charges for all services furnished by Company, including without limitation, Service connection charges, monthly access charges, charges for air time associated with calls originated by or completed to Customer's access number and charges for enhanced features as well as other charges billed to Customer's access number, including sales and use taxes, other taxes required by law, fees or other exactions imposed by or for any municipal or other political authority against Company. In addition, Customer shall pay Company when due for all toll charges resulting from the origination of mobile calls to points outside Company's Service Area, and for all other charges attributable to Customer's access number. Customer also agrees to pay for charges billed to Customer's access number on account of Service provided to Customer as a "roamer" in other cities or Service areas. Rates and charges shall be based on prices in effect at the time Service is furnished.

Payments received after the due date of an invoice may incur a late payment charge of up to the highest rate permitted by law of the unpaid balance for each month or fraction thereof that such balance shall remain unpaid.

In the event that Customer's equipment is lost, stolen or otherwise absent from Customer's possession and control, Customer shall nonetheless be liable for all use, toll, and other usage based charges attributable to the access number assigned to said unit until such time as Company is notified of the loss, theft, or other occurrence. The contract shall not terminate due to any such notice.

When payment for Service or equipment is made by check, draft, or other negotiable instrument, a charge of the maximum amount allowed by law may be made by Company for each such instrument returned unpaid by a bank to Company for any reason except to the extent limited by law.

Unless otherwise agreed by Company, Customer shall be responsible for all outstanding charges for Service rendered and shall be responsible for all charges through the end of the billing cycle within which termination occurs, without proration of any such charge.

DEFAULT AND WAIVER.

In the event that Customer shall default in the payment when due of any sum due hereunder, including refusal of charges by Customer's credit card company, or in the event of any default or breach of the terms and/or conditions of this agreement, or if any proceeding in bankruptcy, receivership or insolvency or petition for receivership shall be instituted by or against Customer, Company, at its option, may.

(i) Proceed by appropriate court action or actions to enforce performance by Customer of the applicable covenants and terms of this agreement or to recover damages for the breach thereof; and/or

(ii) Terminate this agreement, whereupon all rights and interests of Customer shall terminate and Customer shall remain liable for all Services provided.

Customer shall pay to Company on demand any and all past due amounts which Company may sustain by reason of such default or breach by Customer, together with all other charges as provided by this agreement, reasonable attorney's fees incurred by Company in connection with such breach or default by Customer and all other costs and expenses incurred by Company in collecting such amounts. All amounts shall be payable by Customer without setoff or deduction of any kind.

The remedies provided in favor of Company in the event of default shall not be deemed to be exclusive but shall be in addition to all other remedies in its favor existing at law.

No failure on the part of Company to exercise any right or remedy arising directly or indirectly under this agreement shall operate as a waiver of any right or remedy it may have nor shall an exercise of any right or remedy by Company preclude any other right or remedy Company may have.

...FICATE OF AUTHORITY. If Customer is a person, firm, or organization other than the individual user of the Service, the individual agreeing to this agreement on behalf of such Customer hereby certifies having authority to agree on behalf of Customer.

...ANTOR. If Customer is a corporation, partnership or other entity, the signatory on the signature slip of the Service hereby personally guarantees, unconditionally and at all times, the payment when due of any indebtedness of such corporation, partnership or other entity ...pany for the Services and/or equipment provided pursuant to this agreement. The signatory on the signature slip waives notice of any transaction or obligation which Company may create, renew, extend or alter in whole or part from time to time during the term of this ...ment to such corporation, partnership or other entity.

...NMENTS. Neither this agreement nor Customer's rights hereunder shall be assignable by Customer except with Company's prior written consent. The conditions hereof shall bind any permitted successors and assigns of Customer.

...ENT AND GOVERNING LAW. Customer acknowledges that this agreement contains the entire agreement between the parties relating to the services and/or equipment described in this agreement and that Company and its employees have not made orally or in ...esentations, warranties or agreements inconsistent with the terms of this agreement. No modification, change or alteration of any of the terms of this agreement shall be valid unless provided in writing by Company. This agreement supersedes all prior ...understandings, both oral and written, with respect to the subject matter hereof. Customer agrees to notify Company within 10 days of any change of address. ...ment shall be governed by, construed and enforced in accordance with the laws of the state where Company's Mobile Telephone Switching Office for Customer's access number is located. In the event of any conflict between this agreement and the applicable laws or tariffs ...l state, or federal body, such laws or tariffs shall control to the extent applicable.

...ABLE PROVISIONS. If any part of this agreement is contrary to or prohibited by or deemed invalid under applicable laws and regulations of any applicable jurisdiction, the remaining provisions and parts thereof shall remain and be construed in full force and effect to the ...permitted by law.

...TA CARRIER TERMS.

Customer agrees to pay Company a charge for toll restriction if Customer does not want long distance service.

Company shall have no responsibility for any disputes between Customer and any long distance carrier other than Company.

...C SERIAL NUMBER (ESN). The ESN associated with customer's equipment is registered as part of this agreement and customer shall not modify nor permit the modification of this ESN. If such equipment is traded or replaced, Customer must notify Company to register ...ESN.

...AND TERMINATION. Unless Customer or Company terminates this agreement as provided ... [illegible]

... SUCH PERIOD OF ... IN THE EVENT CUSTOMER IS AFFECTED BY SUCH INTERRUPTION FOR A PERIOD OF LESS THAN 24 HOURS, NO ... WHEN AN INTERRUPTION EXCEEDS 24 HOURS, THE LENGTH OF THE INTERRUPTION WILL BE MEASURED IN 24 HOUR DAYS. A FRACTION OF A DAY CONSISTING OF LESS THAN 12 HOURS WILL NOT BE CREDITED, BUT A PERIOD OF 12 HOURS OR MORE WILL BE CONSIDERED AN ADDITIONAL DAY.

(iii) THE CREDIT ALLOWANCE WILL BE COMPUTED BY DIVIDING THE LENGTH OF THE SERVICE INTERRUPTION BY A STANDARD 30 DAY MONTH AND THEN MULTIPLYING THE RESULT BY COMPANY'S FIXED MONTHLY CHARGES FOR EACH INTERRUPTED ACCESS NUMBER. IN NO CASE WILL THE CREDIT EXCEED THE FIXED MONTHLY CHARGES.

(iv) A CREDIT ALLOWANCE WILL NOT BE GIVEN FOR MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS OR DEFECTS, OR CURTAILMENTS IN THE SERVICE CAUSED BY THE NEGLIGENCE OR WILLFUL ACT OF CUSTOMER OR OTHER PARTIES, OR MISTAKES, OMISSIONS INTERRUPTIONS, DELAYS, ERRORS, OR DEFECTS CAUSED BY FAILURE OF EQUIPMENT OR SERVICE NOT PROVIDED BY COMPANY.

(v) THE SERVICE FURNISHED BY COMPANY, IN ADDITION TO THE LIMITATIONS SET FORTH PRECEDING, IS ALSO SUBJECT TO THE FOLLOWING LIMITATION: THE LIABILITY OF COMPANY FOR LOSS OR DAMAGES ARISING OUT OF MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS OR DEFECTS IN THE SERVICE, ITS TRANSMISSION OR FAILURES OR DEFECTS IN FACILITIES OF THE UNDERLYING CARRIER, OCCURRING IN THE COURSE OF FURNISHING SERVICE AND NOT CAUSED BY THE NEGLIGENCE OF THE AUTHORIZED USER, SHALL IN NO EVENT EXCEED AN AMOUNT EQUIVALENT TO THE PROPORTIONATE FIXED MONTHLY CHARGE TO THE CUSTOMER FOR SERVICE DURING THE PERIOD OF TIME IN WHICH SUCH MISTAKES, OMISSIONS, INTERRUPTIONS, DELAYS, ERRORS, OR DEFECTS IN SERVICE, ITS TRANSMISSION, OR FAILURES OR DEFECTS IN FACILITIES FURNISHED BY COMPANY OR THE UNDERLYING CARRIER OCCURRED.

Company shall in no event be liable for service or equipment interruptions or delays in transmission, errors or defects in service or equipment, when caused by acts of God, fire, war, riots, government authorities, default of supplier, or other causes beyond Company's or any carrier's control.

[illegible]tomer acknowledges that Company's systems use radio channels to transmit voice and data communications and that the service may not be completely private. Company is not liable to customer for any claims, loss, damages or cost which may result from lack of [illegible]acy on the system.

(d) CUSTOMER HEREBY AGREES TO INDEMNIFY AND SAVE COMPANY HARMLESS AGAINST CLAIMS FOR LIBEL, SLANDER, OR INFRINGEMENT OR COPYRIGHT FROM THE TRANSMISSION OF MATERIAL IN ANY FORM OVER ITS FACILITIES BY CUSTOMER OR THOSE USING CUSTOMER'S EQUIPMENT; AGAINST CLAIMS FOR INFRINGEMENT OF PATENTS ARISING FROM COMBINING OR USING APPARATUS OR SYSTEMS OF CUSTOMER WITH THE FACILITIES OF COMPANY OR ANY CARRIER; AND AGAINST ALL OTHER CLAIMS ARISING OUT OF ANY ACT OR OMISSION OF CUSTOMER IN CONNECTION WITH THE FACILITIES OR SERVICE PROVIDED BY COMPANY.

Company is not liable for any damage, accident, injury or the like occasioned by the use of Service or the presence of equipment, including cellular units and devices, facsimile units, pagers, and ancillary equipment of Customer or Company except as provided herein.

Company is not liable for any defacement or damage to Customer's motor vehicle or any personal or real property resulting from the presence of radio and ancillary equipment.

(g) THE LIABILITY OF COMPANY IN CONNECTION WITH THE SERVICE PROVIDED IS SUBJECT TO THE FOREGOING LIMITATIONS AND COMPANY MAKES NO WARRANTIES OF ANY KIND, EXPRESSED OR IMPLIED, AS TO THE PROVISION OF SUCH SERVICE.

DISCLAIMER OF WARRANTIES AND LIMITATION OF REMEDIES.

(a) CUSTOMER ACKNOWLEDGES AND AGREES THAT COMPANY IS NOT THE MANUFACTURER OF EQUIPMENT AND COMPANY EXCEPT AS LIMITED BY LAW HEREBY DISCLAIMS ALL REPRESENTATIONS AND WARRANTIES, DIRECT OR INDIRECT, EXPRESS OR IMPLIED, WRITTEN OR ORAL, IN CONNECTION WITH THE EQUIPMENT OR SERVICE (WHETHER PURCHASED OR LEASED BY CUSTOMER FROM COMPANY OR ANOTHER), INCLUDING BUT NOT LIMITED TO ANY AND ALL EXPRESS AND IMPLIED WARRANTIES OF SUITABILITY, DURABILITY, MERCHANTABILITY, AND FITNESS FOR A PARTICULAR PURPOSE. COMPANY TO THE EXTENT PERMITTED BY LAW ASSIGNS TO CUSTOMER ANY AND ALL MANUFACTURERS' WARRANTIES RELATING TO EQUIPMENT PURCHASED BY CUSTOMER, AND CUSTOMER ACKNOWLEDGES RECEIPT OF ANY AND ALL SUCH MANUFACTURERS' WARRANTIES.

(b) CUSTOMER ACKNOWLEDGES AND AGREES THAT ITS SOLE AND EXCLUSIVE REMEDY IN CONNECTION WITH ANY DEFECTS IN THE EQUIPMENT, INCLUDING MANUFACTURE OR DESIGN, SHALL BE AGAINST THE MANUFACTURER OF THE EQUIPMENT UNDER THE MANUFACTURERS' WARRANTIES AND THAT COMPANY SHALL HAVE NO LIABILITY TO CUSTOMER IN ANY EVENT FOR ANY LOSS, DAMAGE, INJURY, OR EXPENSE OF ANY KIND OR NATURE RELATED DIRECTLY OR INDIRECTLY TO ANY EQUIPMENT OR SERVICE PROVIDED HEREUNDER. WITHOUT LIMITING THE ABOVE, COMPANY SHALL HAVE NO LIABILITY OR OBLIGATION TO CUSTOMER, IN EITHER CONTRACT OR TORT, FOR SPECIAL, INCIDENTAL, OR CONSEQUENTIAL DAMAGES OF ANY KIND INCURRED BY CUSTOMER, SUCH AS, BUT NOT LIMITED TO, CLAIMS OR DAMAGES FOR PERSONAL INJURY, WRONGFUL DEATH, LOSS OF USE, LOSS OF ANTICIPATED PROFITS, OR OTHER INCIDENTAL OR CONSEQUENTIAL DAMAGES OR ECONOMIC LOSSES OF ANY KIND INCURRED BY CUSTOMER DIRECTLY OR INDIRECTLY RESULTING FROM OR RELATED TO ANY EQUIPMENT OR SERVICE DESCRIBED HEREUNDER, WHETHER OR NOT CAUSED BY COMPANY'S NEGLIGENCE, TO THE FULL EXTENT SAME MAY BE DISCLAIMED BY LAW. ANY REFERENCES TO EQUIPMENT IN THIS PARAGRAPH SHALL BE DEEMED TO APPLY TO ALL EQUIPMENT PURCHASED BY CUSTOMER OR LEASED BY CUSTOMER FROM COMPANY OR ANOTHER LESSOR. SOME STATES DO NOT ALLOW THE EXCLUSION OR LIMITATION OF INCIDENTAL OR CONSEQUENTIAL DAMAGES SO THE ABOVE EXCLUSION MAY NOT APPLY. YOU MAY ALSO HAVE OTHER LEGAL RIGHTS WHICH VARY FROM STATE TO STATE.

INDEMNIFICATION AND RELEASE. CUSTOMER AGREES TO RELEASE, DEFEND, INDEMNIFY AND HOLD HARMLESS COMPANY, ITS OFFICERS AND EMPLOYEES, TO THE FULL EXTENT PERMITTED BY LAW FROM AND AGAINST ANY AND ALL CLAIMS, DAMAGES, LIABILITIES AND EXPENSES, INCLUDING LEGAL AND ATTORNEY FEES, OF ANY NATURE ARISING DIRECTLY OR INDIRECTLY OUT OF THIS AGREEMENT, INCLUDING, WITHOUT LIMITATION, CLAIMS FOR PERSONAL INJURY OR WRONGFUL DEATH TO CUSTOMER OR USERS OF THE EQUIPMENT, PRODUCTS OR SERVICES PROVIDED BY COMPANY OR USED IN CONJUNCTION WITH SUCH EQUIPMENT, PRODUCTS OR SERVICES PROVIDED BY COMPANY AND ARISING OUT OF THE MANUFACTURE, PURCHASE, OPERATION, CONDITION, MAINTENANCE, INSTALLATION, RETURN OR USE OF THE EQUIPMENT OR SERVICE, OR ARISING BY OPERATION OF LAW, WHETHER THE CLAIM IS BASED IN WHOLE OR IN PART ON NEGLIGENT ACTS OR OMISSIONS OF COMPANY, ITS AGENTS OR EMPLOYEES.

[illegible] AND CHARGES. Unless otherwise agreed by Company, Customer will be billed in advance for monthly access charges and in arrears for usage charges. Usage of Service shall be measured in one minute increments and each partial minute shall be rounded up to the next [illegible] minute increment. Customer will be charged a minimum of one minute for every call that is received or placed using Customer's equipment and sent or answered by the called party. Chargeable time is measured from time of channel seizure to channel termination. Company [illegible] the right to define the hours of peak and off-peak, and nights and weekends calling times and Customer recognizes that scheduling of such times is subject to change and that such changes do not constitute changes in rates. Airtime rates do not include long distance [illegible] for calls beyond Company's local service area.

[illegible]MENT OF CHARGES.

Unless otherwise agreed by Company, Payment is due to Company upon receipt of invoice by Customer. Service may be billed to Customer's credit card.

Customer shall be responsible for payment of charges for all services furnished by Company, including without limitation, Service connection charges, monthly access charges, charges for air time associated with calls originated by or completed to Customer's access number and charges for enhanced features as well as other charges billed to Customer's access number, including sales and use taxes, other taxes required by law, fees or other exactions imposed by or for any municipal or other political authority against Company. In addition, Customer shall pay Company when due for all toll charges resulting from the origination of mobile calls to points outside Company's Service Area, and for all other charges attributable to Customer's access number. Customer also agrees to pay for charges billed to Customer's access number on account of Service provided to Customer as a "roamer" in other cities or Service areas. Rates and charges shall be based on prices in effect at the time Service is furnished.

Payments received after the due date of an invoice may incur a late payment charge of up to the highest rate permitted by law of the unpaid balance for each month or fraction thereof that such balance shall remain unpaid.

In the event that Customer's equipment is lost, stolen or otherwise absent from Customer's possession and control, Customer shall nonetheless be liable for all use, toll, and other usage based charges attributable to the access number assigned to said unit until such time as Company is notified of the loss, theft or other occurrence. The contract shall not terminate due to any such notice.

When payment for Service or equipment is made by check, draft, or other negotiable instrument, a charge of the maximum amount allowed by law may be made by Company for each such instrument returned unpaid by a bank to Company for any reason except to the extent limited by law.

Unless otherwise agreed by Company, Customer shall be responsible for all outstanding charges for Service rendered and shall be responsible for all charges through the end of the billing cycle within which termination occurs, without proration of any such charge.

[illegible]ULT AND WAIVER.

In the event that Customer shall default in the payment when due of any sum due hereunder, including refusal of charges by Customer's credit card company, or in the event of any default or breach of the terms and/or conditions of this agreement, or if any proceeding in [illegible]ruptcy, receivership or insolvency or petition for receivership shall be instituted by or against Customer, Company, at its option, may:

[illegible]ceed by appropriate court action or actions to enforce performance by Customer of the applicable covenants and terms of this agreement or to recover damages for the breach thereof; and/or

[illegible]minate this agreement, whereupon all rights and interests of Customer shall terminate and Customer shall remain liable for all Services provided.

[illegible]er shall pay to Company on demand any and all past due amounts which Company may sustain by reason of such default or breach by Customer, together with all other charges as provided by this agreement, reasonable attorney's fees incurred by Company in connection with such breach or default by Customer and all other costs and expenses incurred by Company in collecting such amounts. All amounts shall be payable by Customer without setoff or deduction of any kind.

The remedies provided in favor of Company in the event of default shall not be deemed to be exclusive but shall be in addition to all other remedies in its favor existing at law.

No failure on the part of Company to exercise any right or remedy arising directly or indirectly under this agreement shall operate as a waiver of any right or remedy it may have nor shall an exercise of any right or remedy by Company preclude any other right or remedy Company may have.

[illegible]CATE OF AUTHORITY. If Customer is a person, firm, or organization other than the individual user of the Service, the individual agreeing to this agreement on behalf of such Customer hereby certifies having authority to agree on behalf of Customer.

[illegible]ANTOR. If Customer is a corporation, partnership or other entity, the signatory on the signature slip of the Service hereby personally guarantees, unconditionally and at all times, the payment when due of any indebtedness of such corporation, partnership or other entity [illegible] for the Services and/or equipment provided pursuant to this agreement. The signatory on the signature slip waives notice of any transaction or obligation which Company may create, renew, extend or alter in whole or part from time to time during the term of this [illegible] to such corporation, partnership or other entity.

[illegible]MENTS. Neither this agreement nor Customer's rights hereunder shall be assignable by Customer except with Company's prior written consent. The conditions hereof shall bind any permitted successors and assigns of Customer.

[illegible] AGREEMENT AND GOVERNING LAW. Customer acknowledges that this agreement contains the entire agreement between the parties relating to the services and/or equipment described in this agreement and that Company and its employees have not made orally or in [illegible] any representations, warranties or agreements inconsistent with the terms of this agreement. No modification, change or alteration of any of the terms of this agreement shall be valid unless provided in writing by Company. This agreement supersedes all prior [illegible]ments and understandings, both oral and written, with respect to the subject matter hereof. Customer agrees to notify Company within 10 days of any change of address

[illegible] shall be governed by, construed and enforced in accordance with the laws of the state where Company's Mobile Telephone Switching Office for Customer's access number is located. In the event of any conflict between this agreement and the applicable laws or tariffs [illegible] state, or federal body, such laws or tariffs shall control to the extent applicable.

[illegible] PROVISIONS. If any part of this agreement is contrary to or prohibited by or deemed invalid under applicable laws and regulations of any applicable jurisdiction, the remaining provisions and parts thereof shall remain and be construed in full force and effect to the [illegible] permitted by law.

[illegible] CARRIER TERMS.

Customer agrees to pay Company a charge for toll restriction if Customer does not want long distance service.

Company shall have no responsibility for any disputes between Customer and any long distance carrier other than Company.

[illegible] SERIAL NUMBER (ESN). The ESN associated with customer's equipment is registered as part of this agreement and customer shall not modify nor permit the modification of this ESN. If such equipment is traded or replaced, Customer must notify Company to register [illegible]

[illegible] AND TERMINATION. Unless Customer or Company terminates this agreement as provided herein, and except as otherwise agreed, upon completion of any initial term, this agreement shall renew on a month-to month basis. Notice of Customer intent to terminate this [illegible] shall be made in writing 30 days prior to the Company. Company reserves the right to not renew this agreement at any time prior to the conclusion of the initial or any renewal term by giving customer notice of same.

Subject to regulatory requirements, Company agrees that it will not increase air time charges per minute or monthly access charges to Customer during the initial term of agreement. Company may from time to time alter the designation of peak and off-peak, and nights [illegible] weekends air time and any additional costs incurred by Customer due to a change in such designations shall not be considered an increase in air time charges per minute. The limitation on rate increases under this paragraph shall apply only to air time charges per [illegible] and "monthly access charges" and Company shall have the option to adjust rates and prices for all other Services from time to time.

[illegible]DATED DAMAGES. CUSTOMER ACKNOWLEDGES AND AGREES THAT CANCELLATION OR TERMINATION OF THIS AGREEMENT OR ANY RENEWAL THEREOF PRIOR TO THE EXPIRATION OF THE AGREED UPON SERVICE PERIOD BY CUSTOMER, OR BY COMPANY FOR REASONS OF [illegible]MER'S DEFAULT, WILL RESULT IN DAMAGES AND LOSS OF PROFITS TO COMPANY WHICH ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE EXACTLY. ACCORDINGLY, THE PARTIES AGREE THAT, IN THE EVENT OF ANY SUCH EARLY CANCELLATION OR TERMINATION OF THIS AGREEMENT, [illegible]MER SHALL THEREUPON PAY TO COMPANY ON DEMAND AS LIQUIDATED DAMAGES AND NOT AS A PENALTY (IN ADDITION TO AMOUNTS PAYABLE UNDER PARAGRAPH 7 ABOVE) AN AMOUNT EQUAL TO THE LIQUIDATED DAMAGES AMOUNT SHOWN ON THE SIGNATURE SLIP [illegible]D BY THE TOTAL NUMBER OF [illegible] IN CUSTOMERS' SERVICE PERIOD MULTIPLIED BY THE REMAINING MONTHS OR PARTS OF MONTHS IN SUCH SERVICE PERIOD.

[illegible]ENDENT ARBITRATION (PLEASE READ THIS PARAGRAPH CAREFULLY. IT AFFECTS RIGHTS THAT YOU MAY OTHERWISE HAVE.)

COMPANY AND CUSTOMER SHALL USE THEIR BEST EFFORTS TO SETTLE ANY DISPUTE OR CLAIM ARISING FROM OR RELATING TO THIS AGREEMENT. TO ACCOMPLISH THIS, THEY SHALL NEGOTIATE WITH EACH OTHER IN GOOD FAITH. IF COMPANY AND CUSTOMER DO NOT REACH AGREEMENT WITHIN 30 DAYS, INSTEAD OF SUING IN COURT, COMPANY AND CUSTOMER AGREE TO ARBITRATE ANY AND ALL DISPUTES AND CLAIMS (INCLUDING BUT NOT LIMITED TO CLAIMS BASED ON OR ARISING FROM AN ALLEGED TORT) ARISING OUT OF OR RELATING TO THIS AGREEMENT, OR TO ANY PRIOR AGREEMENT FOR PRODUCTS OR SERVICE BETWEEN CUSTOMER AND COMPANY OR ANY OF CUSTOMER'S OR COMPANY'S AFFILIATES OR PREDECESSORS IN INTEREST.

NOTWITHSTANDING THE PROVISIONS OF PARAGRAPH (a), NO CLAIM OR DISPUTE SHALL BE SUBMITTED TO ARBITRATION IF, AT THE TIME OF THE PROPOSED SUBMISSION, SUCH DISPUTE OR CLAIM INVOLVES AN ATTEMPT TO COLLECT A DEBT OWED TO THE COMPANY BY THE CUSTOMER.

THE ARBITRATION OF ANY DISPUTE OR CLAIM SHALL BE CONDUCTED IN ACCORDANCE WITH THE WIRELESS INDUSTRY ARBITRATION RULES ("WIA RULES") AS MODIFIED BY THIS AGREEMENT AND AS ADMINISTERED BY THE AMERICAN ARBITRATION ASSOCIATION ("AAA"). THE WIA RULES AND FEE INFORMATION ARE AVAILABLE FROM COMPANY OR THE AAA UPON REQUEST.

COMPANY AND CUSTOMER ACKNOWLEDGE THAT THIS AGREEMENT EVIDENCES A TRANSACTION IN INTERSTATE COMMERCE AND THAT THE UNITED STATES ARBITRATION ACT AND FEDERAL ARBITRATION LAW SHALL GOVERN THE INTERPRETATION AND ENFORCEMENT OF, AND PROCEEDINGS PURSUANT TO, THIS OR A PRIOR AGREEMENT.

[illegible]PANY AND CUSTOMER AGREE OTHERWISE, THE LOCATION OF ANY ARBITRATION SHALL BE IN THE CITY WHERE COMPANY'S MOBILE TELEPHONE SWITCHING OFFICE FOR CUSTOMER'S ACCESS NUMBER IS LOCATED.

[illegible]D CUSTOMER AGREE THAT NO ARBITRATOR HAS THE AUTHORITY TO: (1) AWARD RELIEF IN EXCESS OF WHAT THIS OR A PRIOR AGREEMENT PROVIDES; (2) AWARD PUNITIVE DAMAGES OR ANY OTHER DAMAGES NOT MEASURED BY THE PREVAILING PARTY'S [illegible]UAL DAMAGES; OR (3) ORDER CONSOLIDATION OR CLASS ARBITRATION.

[illegible]CEPT AS OTHERWISE PROVIDED HEREIN, ALL FEES AND EXPENSES OF THE ARBITRATION SHALL BE EQUALLY BORNE BY CUSTOMER AND COMPANY.

THE ARBITRATOR(S) MUST GIVE EFFECT TO THE LIMITATIONS ON COMPANY'S LIABILITY AS SET FORTH IN THIS OR A PRIOR AGREEMENT, ANY APPLICABLE TARIFF, LAW, OR REGULATION.

IN ANY ARBITRATION UTILIZING THE RULES APPLICABLE TO LARGE/COMPLEX CASES, AS DEFINED [illegible] THE WIA RULES, THE ARBITRATORS MUST ALSO APPLY THE FEDERAL [illegible] OF EVIDENCE, AND THE LOSING PARTY MAY HAVE THE AWARD REVIEWED IN ACCORDANCE WITH THE REVIEW PROCEDURES SET FORTH IN THE WIA RULES.

[illegible]STOMER AGREES THAT COMPANY AND CUSTOMER EACH IS WAIVING ITS RESPECTIVE RIGHT TO A TRIAL BY JURY. CUSTOMER [illegible] THAT ARBITRATION IS FINAL AND BINDING AND SUBJECT TO ONLY VERY LIMITED REVIEW BY A COURT. IF FOR SOME REASON THIS [illegible]BITRATION CLAUSE IS AT SOME POINT DEEMED INAPPLICABLE OR INVALID, CUSTOMER AND COMPANY AGREE TO WAIVE, TO THE FULLEST EXTENT ALLOWED BY LAW, ANY TRIAL BY JURY. IN SUCH CASE, A JUDGE SHALL DECIDE THE SUBJECT DISPUTE OR CLAIM.

[illegible]MPANY, CUSTOMER AND ARBITRATOR(S) SHALL NOT DISCLOSE THE EXISTENCE, CONTENT, OR RESULTS OF ANY ARBITRATION [illegible] THE AWARD RENDERED [illegible] ARBITRATOR(S) MAY BE ENTERED IN ANY COURT HAVING JURISDICTION THEREOF

[illegible]

ADDENDUM

The following list of mobile numbers is covered by the BellSouth Mobility Agreement (98767276)

#	Mobile Number	Rate Plan	Contract End Date
1	5023161075	$ 20.00	3/15/00
2	5023161200	$ 20.00	2/26/00
3	5023161201	$ 20.00	2/26/00
4	5023161202	$ 20.00	2/26/00
5	5023161203	$ 20.00	2/26/00
6	5023161204	$ 20.00	2/26/00
7	5023161205	$ 20.00	2/26/00
8	5023161206	$ 20.00	2/26/00
9	5023161207	$ 20.00	2/26/00
10	5023161208	$ 20.00	2/26/00
11	5023161209	$ 20.00	2/26/00
12	5023161210	$ 20.00	2/26/00
13	5023161211	$ 20.00	2/26/00
14	5023161212	$ 20.00	2/26/00
15	5023161213	$ 20.00	2/26/00
16	5023161214	$ 20.00	2/26/00
17	5023161215	$ 20.00	2/26/00
18	5023161216	$ 20.00	2/26/00
19	5023161217	$ 20.00	2/26/00
20	5023161218	$ 20.00	2/26/00
21	5023161219	$ 20.00	2/26/00
22	5023161220	$ 20.00	2/26/00
23	5023161221	$ 20.00	2/26/00
24	5023161222	$ 20.00	2/26/00
25	5023161223	$ 20.00	2/26/00
26	5023161224	$ 20.00	2/26/00
27	5023161225	$ 20.00	2/26/00
28	5023161226	$ 20.00	2/26/00
29	5023161227	$ 20.00	2/26/00
30	5023161228	$ 20.00	2/26/00
31	5023161229	$ 20.00	2/26/00
32	5023161230	$ 20.00	2/26/00
33	5023161231	$ 20.00	2/26/00
34	5023161232	$ 20.00	2/26/00
35	5023161233	$ 20.00	2/26/00
36	5023161234	$ 20.00	2/26/00
37	5023161235	$ 20.00	2/26/00
38	5023161236	$ 20.00	2/26/00
39	5023161237	$ 20.00	2/26/00
40	5023161238	$ 20.00	2/26/00
41	5023161239	$ 20.00	2/26/00
42	5023161240	$ 20.00	2/26/00
43	5023161241	$ 20.00	2/26/00

44	5023161242	$	20.00	2/26/00
45	5023161243	$	20.00	2/26/00
46	5023161244	$	20.00	2/26/00
47	5023161245	$	20.00	2/26/00
48	5023161246	$	20.00	2/26/00
49	5023161247	$	20.00	2/26/00
50	5023161248	$	20.00	2/26/00
51	5023161249	$	20.00	2/26/00
52	5023161250	$	20.00	2/26/00
53	5023161251	$	20.00	2/26/00
54	5023161252	$	20.00	2/26/00
55	5023161253	$	20.00	2/26/00
56	5023161254	$	20.00	2/26/00
57	5023161255	$	20.00	2/26/00
58	5023161256	$	20.00	2/26/00
59	5023161257	$	20.00	2/15/00
60	5023161258	$	20.00	2/15/00
61	5023161259	$	15.00	4/14/01
62	5023161260	$	15.00	4/14/01
63	5023161261	$	20.00	2/26/00
64	5023161262	$	15.00	4/14/01
65	5023161263	$	15.00	11/4/00
66	5023161264	$	15.00	4/14/01
67	5023161265	$	15.00	4/14/01
68	5023163031	$	15.00	4/14/01
69	5023163462	$	15.00	11/19/00
70	5023163463	$	15.00	11/19/00
71	5023163464	$	15.00	11/19/00
72	5023163465	$	15.00	11/19/00
73	5023163466	$	15.00	11/19/00
74	5023163467	$	15.00	11/19/00
75	5023163468	$	15.00	11/19/00
76	5023163469	$	15.00	11/19/00
77	5023163470	$	15.00	11/19/00
78	5023163803	$	15.00	1/28/01
79	5023163804	$	15.00	1/28/01
80	5023164065	$	20.00	4/21/01
81	5023164069	$	20.00	4/21/01
82	5023164094	$	20.00	4/21/01
83	5023164275	$	20.00	3/10/01
84	5023164276	$	20.00	3/10/01
85	5023166685	$	15.00	3/31/01
86	5023166686	$	15.00	3/31/01
87	5023166687	$	15.00	3/31/01
88	5023166688	$	15.00	3/31/01
89	5023166689	$	15.00	3/31/01
90	5023166690	$	15.00	3/31/01
91	5023166691	$	15.00	3/31/01
92	5023166692	$	15.00	3/31/01

93	5023166693	$	15.00	3/31/01
94	5023166694	$	15.00	3/31/01
95	5023166695	$	15.00	3/31/01
96	5023166696	$	15.00	3/31/01
97	5023166697	$	15.00	3/31/01
98	5023166698	$	15.00	3/31/01
99	5023166699	$	15.00	3/31/01
100	5023166700	$	15.00	3/31/01
101	5023166701	$	15.00	3/31/01
102	5023166702	$	15.00	3/31/01
103	5023166703	$	15.00	3/31/01
104	5023166704	$	15.00	3/31/01
105	5023166705	$	15.00	3/31/01
106	5023166706	$	15.00	3/31/01
107	5023166707	$	15.00	3/31/01
108	5023166708	$	15.00	3/31/01
109	5023166709	$	15.00	3/31/01
110	5023166710	$	15.00	3/31/01
111	5023166711	$	15.00	3/31/01
112	5023166712	$	15.00	3/31/01
113	5023166713	$	15.00	3/31/01
114	5023166714	$	15.00	3/31/01
115	5023166715	$	15.00	3/31/01
116	5023166716	$	15.00	3/31/01
117	5023166717	$	15.00	3/31/01
118	5023166718	$	15.00	3/31/01
119	5023166719	$	15.00	3/31/01
120	5023166720	$	15.00	3/31/01
121	5023166721	$	15.00	3/31/01
122	5023166722	$	15.00	3/31/01
123	5023166723	$	15.00	3/31/01
124	5023166724	$	15.00	3/31/01
125	5023166725	$	15.00	3/31/01
126	5023167811	$	20.00	4/23/01
127	5023167812	$	20.00	4/23/01
128	5023167813	$	20.00	4/23/01
129	5023167822	$	20.00	4/28/01
130	5023167823	$	20.00	4/28/01
131	5023167828	$	15.00	4/29/01
132	5023167829	$	15.00	4/29/01
133	5023167830	$	15.00	4/29/01
134	5023167831	$	15.00	4/29/01
135	5023167832	$	15.00	4/29/01
136	5029290930	$	15.00	4/14/01
137	5029291540	$	15.00	4/14/01
138	5029291862	$	15.00	12/16/98
139	5029292393	$	15.00	4/14/01
140	5029292462	$	15.00	4/14/01
141	5029292463	$	15.00	4/14/01

142	5029292503	$	15.00	4/14/01
143	5029292504	$	15.00	4/14/01
144	5029293108	$	15.00	4/14/01
145	5029293205	$	15.00	4/14/01
146	5029293211	$	15.00	4/14/01
147	5029293455	$	15.00	4/14/01
148	5029294787	$	15.00	4/14/01
149	5029294792	$	15.00	4/14/01
150	5029294794	$	15.00	4/14/01
151	5029294894	$	15.00	4/14/01
152	5029294906	$	15.00	4/14/01
153	5029294931	$	15.00	4/14/01
154	5029294932	$	15.00	4/14/01
155	5029294939	$	15.00	4/14/01
156	5029294947	$	15.00	4/14/01
157	5029294977	$	15.00	4/14/01
158	5029294995	$	15.00	4/14/01
159	5029295053	$	15.00	4/14/01
160	5029295067	$	15.00	4/14/01
161	5029295071	$	15.00	4/14/01
162	5029295085	$	15.00	4/14/01
163	5029295094	$	15.00	4/14/01
164	5029295107	$	15.00	4/14/01
165	5029295686	$	15.00	4/14/01
166	5029296311	$	15.00	4/14/01
167	5029298106	$	15.00	4/14/01
168	5029298155	$	15.00	3/11/01
169	5029298334	$	15.00	4/14/01
170	5029298457	$	15.00	4/14/01
171	5029298844	$	20.00	3/15/00
172	5029298881	$	15.00	4/14/01
173	5029298901	$	15.00	3/15/00
174	5029298902	$	15.00	4/14/01
175	5029298904	$	1,600.00	3/15/00
176	5029298921	$	15.00	4/14/01
177	5029298922	$	15.00	4/14/01
178	5029298976	$	15.00	4/14/01
179	5029299101	$	15.00	4/14/01
180	5029299104	$	15.00	4/14/01
181	5029299944	$	15.00	4/14/01

Customer Signature

BMI Representative Signature

Date:

Date: 7/29/99

Schedule DR 71

Category	Plant Account		WKG
Field Hardware			
MDT			
Server Hardware	399.010	$	73,300
Server Software	399.020		68,800
Application Software	399.080		200,700
Hardware	399.060		609,900
Total		$	952,700

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 72 a,b,c
Witness: Betty Adams

Data Request:

Refer to Ms. Adams' testimony. Provide an explanation, complete with a quantified determination, of how the increase in uncollectible write-offs was calculated for the forecasted test period.

a. Provide the accounts receivable aging schedules for the last two fiscal years.
b. Explain why under-budgeted write-offs for the six-month period in FY 1999 provided sufficient reason to adjust the forecasted period.
c. Provide an accounts receivable aging schedule for the last month of actual results in the test period.

Response:

The increase in uncollectible write-offs was calculated for the forecast year by comparing the actual write-offs of the FY98 with our base year budget. As you will see the actual dollars in account 904 on the attached schedule titled RESP-30, is $706,442 and our budget for the base year according to O&M expense budget as shown on the schedule BUD REPT is $462,478. The assumption was that the write-offs were under budgeted for the base period, and we had no reason to not think that this trend would continue.

a. This type of schedule is not available with the billing system used prior to June 1999. With our new billing system which is one of our various service improvement programs implement as of June 1, 1999, this information will be available.
b. The actual write-offs for the first six months of FY99 is $320,650 which is for the billing period ending December 1998. Due to the procedure of the timing of unpaid accounts to be written off, (which is three months) the months with the higher billings will be written in the second half of the year.
c. See response to "a" above.

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/98

DR 72
Page 1 of 3

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV (UNFAV) COMPARED TO LST YR	NARUC ACCOUNT		YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV (UNFAV) COMPARED TO LST YR
0	0	0 %	742	MFG GAS PROD-MAINT-PROD EQUIP	2	0	(100)%
0	0	0 %	750	NG PROD-OPT-SUPRV & ENGRNG	126	0	(100)%
46	183	75 %	756	NG PROD-OPT-FIELD MEAS & REG	1,106	1,227	10 %
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
0	9	100 %	766	NG PROD-MAINT-FIELD MEAS & REG	332	1,957	83 %
101	94	(7)%	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,189	1,132	(5)%
2,287	1,175	(95)%	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	24,333	22,182	(10)%
812	(643)	(226)%	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	(1,471)	2,386	162 %
3,506	9,268	62 %	816	NG STORG-UNDRGRND-OPT-WELLS EXP	64,139	75,904	15 %
3,547	1,970	(80)%	817	NG STORG-UNDRGRND-OPT-LINES EXP	51,538	36,415	(42)%
4,699	7,420	37 %	818	NG STORG-UNDRGRND-OPT-COMP EXP	58,400	89,630	35 %
0	7,354	100 %	819	NG STORG-UNDRGRND-OPT-COMP PWR	14,074	24,647	43 %
3,034	1,414	(115)%	820	NG STORG-UNDRGRND-OPT-MEAS REG	39,338	20,768	(89)%
752	552	(36)%	821	NG STORG-UNDRGRND-OPT-PURIF EXP	29,685	25,072	(18)%
371	514	28 %	824	NG STORG-UNDRGRND-OPT-OTHER EXP	5,136	5,453	6 %
3,521	1,927	(83)%	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	40,593	37,477	(8)%
0	1,297	100 %	826	NG STORG-UNDRGRND-OPT-RENTS	0	15,560	100 %
0	51	100 %	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	2,449	4,922	50 %
0	0	0 %	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	1,121	784	(43)%
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	51	0	(100)%
155	0	(100)%	834	NG STORG-UNDRGRND-MAINT COMP STN	5,855	6,150	5 %
0	0	0 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	1,966	4,128	52 %
190	47	(304)%	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	2,175	4,714	54 %
0	0	0 %	847	OTHR STRG EXP-MNT LIQ EQUIP	152	0	(100)%
1,441	0	(100)%	850	TRANS-OPT-SUPRV & ENGINEERING	12,936	9,538	(36)%
29,013	28,097	(3)%	856	TRANS-OPT MAINS EXPENSES	222,091	197,509	(12)%
10,479	16,768	38 %	857	TRANS-OPT MEA & REG STAT EXP	114,219	124,273	8 %
188	0	(100)%	859	TRANS-OPT-OTHER EXPENSES	188	0	(100)%
424	0	(100)%	862	TRANS-MAINT-STRUCT & IMPROVMENTS	4,218	3,610	(17)%
3,890	193	(1916)%	863	TRANS-MAINT-MAINT OF MAINS	7,006	8,120	14 %
0	0	0 %	864	TRANS-MAINT COMP ST EQUIP	62	0	(100)%
1,910	2,604	27 %	865	TRANS-MAINT-MEAS & REG STATN EQUIP	30,861	39,700	22 %
0	0	0 %	867	TRANS-MAINT OTH EQUIPMENT	489	0	(100)%
207,744	172,251	(21)%	870	DISTRIB-OPT-SUPRV & ENGINEERING	2,128,482	1,606,647	(32)%
16,697	29,581	44 %	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	282,773	365,348	23 %
0	0	0 %	872	DISTRIB-OPT-COMP STAT LABOR & EXPENSE	72	0	(100)%
163,791	98,562	(66)%	874	DISTRIB-OPT-MAINS & SERVICES	1,532,293	1,056,501	(45)%
7,825	10,337	24 %	875	DISTRIB-OPT-MEAS & REG STAT-GEN	93,204	103,121	10 %
20,693	22,113	6 %	876	DISTRIB-OPT-MEAS & REG STAT-IND	244,866	273,892	11 %
9,244	12,215	24 %	877	DISTRIB-OPT-MEAS & REG CITY GATE	174,523	188,874	8 %
112,358	132,141	15 %	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,292,534	1,208,555	(7)%
67,982	83,554	19 %	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	731,664	817,656	11 %
3,951	6,648	41 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	44,801	55,046	19 %
110,773	106,910	(4)%	881	DISTRIB-OPT-RENTS/BLDG SRV	1,281,091	1,254,419	(2)%
44,492	48,514	8 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	414,818	460,686	10 %
495	653	24 %	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	15,027	22,267	33 %
12,110	8,305	(46)%	887	DISTRIB-MAINT-MAINT OF MAINS	65,287	103,242	37 %
3,308	610	(442)%	889	DISTRIB-MEAS & REG STAT - GEN	17,385	15,270	(14)%

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/98

REF: RESP-30
ISSUED 11/07/98

DR 72

************ THIS MONTH ************					************* YEAR TO DATE *************		
ACTUAL	LAST YR	FAV(UNFAV) COMPARED TO LST YR			ACTUAL	LAST YR	FAV(UNFAV) COMPARED TO LST YR
3,962	4,290	8 %	890	DISTRIB-MEAS & REG STAT - IND	45,655	47,018	3 %
4,943	3,752	(32)%	891	DISTRIB-MEAS & REG STAT - CITY GATE	45,010	59,930	25 %
3,515	3,731	6 %	892	DISTRIB-MAINT OF SERVICE	26,246	22,469	(17)%
2,601	37,713	93 %	893	DISTRIB-MTRS & HOUSE REG	235,703	186,360	(26)%
521	154	(238)%	894	DISTRIB-MAINT-OTHER EQUIPMENT	8,364	9,034	7 %
7,366	27,934	74 %	901	CUS ACT EX-OPT-SUPERVISION	158,764	342,434	54 %
80,990	86,010	6 %	902	CUS ACT EX-OPT-METER READING EXP	1,038,732	1,053,793	1 %
6,121	173,082	96 %	903	CUS ACT EX-OPT-CUS REC/COLL EXP	669,663	2,051,670	67 %
140,507	(1,531)	(9277)%	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	706,442	501,885	(41)%
0	0	0 %	905	CUS ACT EX-OPT-MISC CUST AC EXP	20	0	(100)%
44,111	9,981	(342)%	909	CUS SRV EXP-OPT-SUPERVISION	279,920	106,085	(164)%
52,712	95,177	45 %	910	CUS SRV EXP-OPT-CUSTMR ASSIST	828,862	959,355	14 %
9,054	12,763	29 %	911	CUST SRV EXP-OPT-INFRM ADV EXP	63,008	86,229	27 %
1,193	783	(52)%	915	SALE PROMO EXP-OPT-SUPERVISION	9,000	3,963	(127)%
3,803	2,460	(55)%	916	SALE PROMO EXP-OPT-DEMO & SELL	67,730	52,238	(30)%
0	0	0 %	917	SALE PROMO EXP-OPT-PROMO ADV	1,097	0	(100)%
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	3,753	5,281	29 %
0	0	0 %	920	ADM&GEN EX-OPT-ADM&GEN SALARY	11,100	0	(100)%
0	0	0 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	145	142	(2)%
0	0	0 %	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	3,186	0	(100)%
124,807	6,107	(1944)%	925	A&G EX-OPT INJR&DAMG INS DR/CR	231,448	91,662	(153)%
6,261	333,433	98 %	926	A&G EX-OPT-EMP WELF/PENS DR/CR	1,819,723	2,797,081	35 %
0	0	0 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	14,862	19,323	23 %
350	200	(75)%	9302	A&G EX-OPT-MISC GENERAL EXP	38,890	36,795	(6)%
1,344,646	1,608,727	16 %		TOTAL NET EXPENSES	15,360,602	16,727,629	8 %

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DR 72
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ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY
CO DIV W

OPERATION AND MAINTENANCE EXPENSE BUDGET
REQUESTED 1999

REF: BUDREPT
ISSUED 10/20/98

	OCT APR	NOV MAY	DEC JUN	JAN JUL	FEB AUG	MAR SEP	TOTAL
COMPANY LABOR EXPENSE:							
EXECUTIVE PAYROLL	8,602 9,075	8,212 8,662	8,992 9,075	8,662 9,075	8,250 9,075	9,487 9,075	106,242
EXEMPT PAYROLL	168,843 163,255	168,101 162,465	170,140 164,709	162,185 165,481	161,235 165,692	164,205 165,800	1,982,111
OPERATING PAYROLL	421,583 432,358	423,440 432,914	425,458 435,354	430,413 434,714	430,693 434,682	431,829 436,685	5,170,123
EMPLOYEE BENEFITS	137,777 139,077	137,944 138,931	139,057 140,102	138,290 140,131	138,042 140,173	139,270 140,658	1,669,452
TOTAL COMPANY LABOR	736,805 743,765	737,697 742,972	743,647 749,240	739,550 749,401	738,220 749,622	744,791 752,218	8,927,928
MATERIALS & SUPPLIES	35,733 35,533	30,341 30,441	30,436 30,533	35,533 35,461	30,291 30,441	30,316 30,533	385,592
TRANSPORTATION	64,182 64,182	64,182 64,182	64,182 64,181	64,182 64,181	64,182 64,181	64,182 64,181	770,180
OTHER:							
DEPT. SPECIFIC	184,628 162,802	176,031 162,802	174,431 164,402	172,431 168,755	167,081 165,902	170,802 168,882	2,038,949
ADMINISTRATIVE	130,974 113,589	117,429 106,416	120,977 112,586	112,276 105,636	104,314 108,013	106,943 102,958	1,342,111
OUTSIDE SERVICES	14,182 13,782	13,682 18,682	13,682 19,082	13,682 18,682	14,082 18,682	13,682 13,682	185,584
OTHER DEPT. DIRECT	85,146 106,728	57,820 54,876	64,395 45,922	92,572 59,197	52,687 44,156	47,317 45,936	756,752
ALLOCATIONS & OTHER	0 0	0 0	0 0	0 0	0 0	0 0	0
ALLOCATIONS - OUT	0 0	0 0	0 0	0 0	0 0	0 0	0
TOTAL OTHER	414,930 396,901	364,962 342,776	373,485 341,992	390,961 352,270	338,164 336,753	338,744 331,458	4,323,396
REVENUE/REIMBURSEMENT	25,120 22,584	(21,555) 72,697	(11,668) (80,223)	163,149 29,953	54,815 38,924	90,044 78,638	462,478
TOTAL NET EXPENSES	1,276,770 1,262,965	1,175,627 1,253,068	1,200,082 1,105,723	1,393,375 1,231,266	1,225,672 1,219,921	1,268,077 1,257,028	14,869,574

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 72 d,e,f
Witness: Betty Adams

Data Request:

Refer to Ms. Adams' testimony. Provide an explanation, complete with a quantified determination, of how the increase in uncollectible write-offs was calculated for the forecasted test period.

d. Provide an account analysis of Western's reserve for uncollectibles comparing the actual charge-offs with the to date provision for uncollectibles(expense) for the six-month period of actual results in the FY 1999 that comprises part of the base year. If different, schedule Western's monthly provision for uncollectibles(expense) in comparison to the year-to-date("YTD") budget.

e. Provide a comparison of the YTD budget to actual provision for uncollectibles(expense) for the last two fiscal years.

f. Provide a comparison of the reserve for uncollectibles to accounts receivable for FY 1997, FY 1998 and the end of the six-month actual period included in the base year.

Response:

d. See Schedule 72 d (attached) for the analysis of Western's reserve for uncollectibles comparison to actual write-offs.

e. Attached are copies of the requested budget to actual comparison for the uncollectibles (expense)

f. See Schedule 72 f (attached) for the comparison of the reserve for uncollectibles to accounts receivable.

Western Kentucky Gas Company
Rate Case #99-070
Reserve to Expense Comparison

DR 72(d)

	Expense Amount	Reserve Balance	Ratio of Expense to Reserve
October 1998	$ 44,723	$ 172,650	25.90%
November 1998	44,723	172,650	25.90%
December 1998	(30,385)	173,324	-17.53%
January 1999	100,774	173,324	58.14%
February 1999	186,607	173,324	107.66%
March 1999	46,580	173,324	26.87%

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY ELEMENT GROUP
FOR THE MONTH ENDED 09/29/98

DR 72 (E)
Page 1 of 2

THIS MONTH						YEAR TO DATE				
ACTUAL	BUDGET	FAV (UNFAV) COMPARED TO BUDGET	LAST YR	FAV (UNFAV) COMPARED TO LST YR		ACTUAL	BUDGET	FAV (UNFAV) COMPARED TO BUDGET	LAST YR	FAV (UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
8,598	7,235	(19)%	6,944	(24)%	EXECUTIVE PAYROLL	95,101	85,980	(11)%	82,627	(15)%
161,452	137,719	(17)%	213,652	24 %	EXEMPT PAYROLL	1,805,637	1,881,871	4 %	2,316,795	22 %
431,693	431,814	0 %	558,789	23 %	OPERATING PAYROLL	5,653,106	6,035,438	6 %	6,453,672	12 %
23,038	173,032	87 %	332,630	93 %	EMPLOYEE BENEFITS	1,823,234	2,401,028	24 %	2,774,749	34 %
624,781	749,800	17 %	1,112,015	44 %	TOTAL COMPANY LABOR	9,377,078	10,404,317	10 %	11,627,843	19 %
52,199	23,712	(120)%	36,807	(42)%	MATERIALS & SUPPLIES	444,275	338,943	(31)%	376,479	(18)%
69,133	58,706	(18)%	58,815	(18)%	TRANSPORTATION	791,467	704,680	(12)%	663,822	(19)%
					OTHER:					
226,259	226,588	0 %	223,532	(1)%	DEPARTMENTAL SPECIFIC	2,066,620	2,409,878	14 %	2,075,668	0 %
114,201	27,422	(316)%	51,555	(122)%	ADMINISTRATIVE	938,295	334,844	(180)%	295,234	(218)%
21,966	6,555	(235)%	7,360	(198)%	OUTSIDE SERVICES	163,822	79,860	(105)%	123,906	(32)%
74,716	53,644	(39)%	8,420	(787)%	OTHER DEPARTMENT DIRE	626,509	711,527	12 %	436,892	(43)%
28	45,160	100 %	101,107	100 %	ALLOCATIONS & OTHER	256,227	729,099	65 %	668,413	62 %
437,170	359,369	(22)%	391,974	(12)%	TOTAL OTHER	4,051,473	4,265,208	5 %	3,600,113	(13)%
1,183,283	1,191,587	1 %	1,599,611	26 %	TOTAL INCURRED COST	14,664,293	15,713,148	7 %	16,268,257	10 %
161,366	213,779	24 %	9,118	(1669)%	REV/REIMBRSEMNTS/UNCOLL	696,309	393,200	(77)%	459,372	(52)%
1,344,649	1,405,366	4 %	1,608,729	16 %	TOTAL NET EXPENSES	15,360,602	16,106,348	5 %	16,727,629	8 %

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) 745,746

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ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

RESPONSIBILITY MANAGEMENT REPORT
BY ELEMENT GROUP
FOR THE MONTH ENDED 09/29/97

PAGE: 1
REF: RESP-10
ISSUED 11/11/97

DR 72(E)
Page 2 of 2

CO DIV W

THIS MONTH						YEAR TO DATE				
ACTUAL	BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR		ACTUAL	BUDGET	FAV(UNFAV) COMPARED TO BUDGET	LAST YR	FAV(UNFAV) COMPARED TO LST YR
					COMPANY LABOR:					
6,944	6,981	1 %	6,689	(4)%	EXECUTIVE PAYROLL	82,627	82,896	0 %	79,472	(4)%
213,652	225,545	5 %	182,445	(17)%	EXEMPT PAYROLL	2,316,795	2,675,542	13 %	2,304,569	(1)%
558,789	558,318	0 %	528,873	(6)%	OPERATING PAYROLL	6,453,672	6,619,072	2 %	6,325,378	(2)%
332,630	213,398	(56)%	195,868	(70)%	EMPLOYEE BENEFITS	2,774,749	2,531,941	(10)%	1,779,242	(56)%
1,112,015	1,004,242	(11)%	913,875	(22)%	TOTAL COMPANY LABOR	11,627,843	11,909,451	2 %	10,488,661	(11)%
36,807	30,071	(22)%	49,345	25 %	MATERIALS & SUPPLIES	376,479	441,258	15 %	421,886	11 %
58,815	47,128	(25)%	51,776	(14)%	TRANSPORTATION	663,822	582,680	(14)%	602,873	(10)%
					OTHER:					
223,532	181,317	(23)%	144,496	(55)%	DEPARTMENTAL SPECIFIC	2,075,668	2,146,899	3 %	1,539,544	(35)%
51,515	30,601	(68)%	28,002	(84)%	ADMINISTRATIVE	295,193	447,981	34 %	265,341	(11)%
7,360	33,930	78 %	35,510	79 %	OUTSIDE SERVICES	123,906	587,611	79 %	168,715	27 %
8,420	12,808	34 %	(34,486)	(124)%	OTHER DEPARTMENT DIRE	436,892	225,427	(94)%	208,038	(110)%
101,107	36,255	(179)%	124,371	19 %	ALLOCATIONS & OTHER	668,413	435,392	(54)%	661,489	(1)%
391,934	294,911	(33)%	297,893	(32)%	TOTAL OTHER	3,600,072	3,843,310	6 %	2,843,127	(27)%
1,599,571	1,376,352	(16)%	1,312,889	(22)%	TOTAL INCURRED COST	16,268,216	16,776,699	3 %	14,356,547	(13)%
0	0	100 %	0	100 %	ALLOCATIONS - OUT	0	(601,604)	(100)%	0	100 %
9,118	(220,906)	(104)%	227,180	95 %	REV/REIMBRSEMNTS/UNCOLL	459,372	109,953	(317)%	368,000	(25)%
1,608,689	1,155,446	(39)%	1,540,069	(4)%	TOTAL NET EXPENSES	16,727,588	16,285,048	(3)%	14,724,547	(14)%

TOTAL BUDGETED DOLLARS REMAINING (TOTAL FISCAL YEAR BUDGET LESS YTD ACTUAL) (442,540)

LAST PAGE OF REPORT

Western Kentucky Gas Company
Rate Case #99-070
Reserve to Receivable Comparison

	Accounts Receivable Balance	Reserve Balance	Ratio of Reserve to Receivable
Fiscal Year 1997	$ 10,185,958	$ 170,000	1.67%
Fiscal Year 1998	3,434,044	172,650	5.03%
Fiscal YTD 1999 @ 3-31-99	11,900,015	173,324	1.46%

73

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 73
Witness: Betty Adams

Data Request:

In Volume 10 of 10 of the Application, Schedule D2.2, Sheet2 of 2, "ADJ 7" includes the "transfer of Human Resources expenses from Shared Services of $67,700."

a. Provide a list of the job(s) transferred, an explanation of the previous job(s) function with Shared Services, and an explanation of the job(s) function with Western.

b. Did similar job reclassifications occur with Western's gas distribution affiliates? If yes, give an explanation of the reasoning. If no, why not?

Response:

a. There were not any jobs transferred. In previous years Shared Services received the costs for the DOT and Drug testing ($20,000) that was required as well as the cost of the employee service awards ($47,700).

b. All of Western's gas distribution affiliates received their portion of the same type charges.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 74
Witness: Betty Adams

Data Request:

In Volume 10 of 10 of the Application, Schedule D2.3, Sheet 1 of 1, "ADJ 2" is described as an adjustment to "reflect the amortization of the PSC Assessment for 1997 paid in 1999." Provide a detailed explanation and calculations to support the determination of this adjustment.

Response:

The PSC Assessment for 1997, was only half of the adjustment. The estimated for the period was approximately half of the previous year's assessment due to our decrease in revenues. Our 1998 assessment was $276.113 and 1999 it was $167,742.

Below you will find the calculations to support this adjustment.

Prior years amount paid	$ 230,394
Expensed in 1997	(30,325)
Amount to be exp.(Oct, Nov. Dec. 99)	(20,836)
Additional amount expenses in FY 1998	177,232
Expected lower assessment to be expensed In calendar 2000	97,942
Total of decreased expense	$ 275,184

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 75
Witness: Betty Adams

Data Request:

Refer to Ms. Adams' testimony at page 10, line 6, where adjustments to Western's FY 1999 budget decreasing O & M expenses and increasing Shared Services expenses are discussed in regard to the utilization of the new "Customer Support Center in Amarillo, Texas." Provide quantified schedules, referenced to Western's chart of accounts, with explanations of the cost shifts discussed, i.e., decreased number of employees by job classification to Western, new charges by Shared Services.

Response:

See response to DR 8. Much of the information necessary to develop the requested schedules is not available. Merger and reorganization tied to the various service improvement programs, including establishment of the Customer Support Center, makes it impossible to compare pre- and post-re-organizational costs by NARUC account.

For example, the attached report (RESP-30) shows $669,663 in account 903, where most of the FY98 labor costs associated with business office personnel was recorded. Please refer to FR 10(10)(d)1, Schedule D-1, Sheet 3 of 4, for the FY99 base period cost in account 903 of $64,355. This indicates the relative level of cost reduction associated with the closing of WKG's business offices. However, most costs associated with the transfer of responsibilities to Shared Services, including the Customer Support Center, is not recorded in a separate NARUC account other than account 922 where almost all Shared Services costs reside.

The only way to reasonably compare pre- and post-re-organizational changes is on a total cost basis as reflected in DR 8.

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/98

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV (UNFAV) COMPARED TO LST YR	NARUC ACCOUNT		YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV (UNFAV) COMPARED TO LST YR
0	0	0 %	742	MFG GAS PROD-MAINT-PROD EQUIP	2	0	(100)%
0	0	0 %	750	NG PROD-OPT-SUPRV & ENGRNG	126	0	(100)%
46	183	75 %	756	NG PROD-OPT-FIELD MEAS & REG	1,106	1,227	10 %
0	0	0 %	758	NG PROD-OPT-GAS WELLS ROYALTY	100	100	0 %
0	9	100 %	766	NG PROD-MAINT-FIELD MEAS & REG	332	1,957	83 %
101	94	(7)%	798	EXPL&DEV-OPT-TRANSFR-PGA-CR-OPT	1,189	1,132	(5)%
2,287	1,175	(95)%	807	OTH GAS SUPPLY-OPT-WELL EXP-PU	24,333	22,182	(10)%
812	(643)	(226)%	814	NG STORG-UNDRGRND-OPT-SUP&ENGR	(1,471)	2,386	162 %
3,506	9,268	62 %	816	NG STORG-UNDRGRND-OPT-WELLS EXP	64,139	75,904	15 %
3,547	1,970	(80)%	817	NG STORG-UNDRGRND-OPT-LINES EXP	51,538	36,415	(42)%
4,699	7,420	37 %	818	NG STORG-UNDRGRND-OPT-COMP EXP	58,400	89,630	35 %
0	7,354	100 %	819	NG STORG-UNDRGRND-OPT-COMP PWR	14,074	24,647	43 %
3,034	1,414	(115)%	820	NG STORG-UNDRGRND-OPT-MEAS REG	39,338	20,768	(89)%
752	552	(36)%	821	NG STORG-UNDRGRND-OPT-PURIF EXP	29,685	25,072	(18)%
371	514	28 %	824	NG STORG-UNDRGRND-OPT-OTHER EXP	5,136	5,453	6 %
3,521	1,927	(83)%	825	NG STORG-UNDRGRND-OPT-WELL ROYLTY	40,593	37,477	(8)%
0	1,297	100 %	826	NG STORG-UNDRGRND-OPT-RENTS	0	15,560	100 %
0	51	100 %	831	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	2,449	4,922	50 %
0	0	0 %	832	NG STORG-UNDRGRND-MAINT/SUPRV/ENGNRNG	1,121	784	(43)%
0	0	0 %	833	NG STORG-UNDRGRND-MAINT OF LINES	51	0	(100)%
155	0	(100)%	834	NG STORG-UNDRGRND-MAINT COMP STN	5,855	6,150	5 %
0	0	0 %	835	NG STORG-UNDRGRND-MAINT/MEAS/REG	1,966	4,128	52 %
190	47	(304)%	836	NG STORG-UNDRGRND-MAINT/PURIF EQUIP	2,175	4,714	54 %
0	0	0 %	847	OTHR STRG EXP-MNT LIQ EQUIP	152	0	(100)%
1,441	0	(100)%	850	TRANS-OPT-SUPRV & ENGINEERING	12,936	9,538	(36)%
29,013	28,097	(3)%	856	TRANS-OPT MAINS EXPENSES	222,091	197,509	(12)%
10,479	16,768	38 %	857	TRANS-OPT MEA & REG STAT EXP	114,219	124,273	8 %
188	0	(100)%	859	TRANS-OPT-OTHER EXPENSES	188	0	(100)%
424	0	(100)%	862	TRANS-MAINT-STRUCT & IMPROVMENTS	4,218	3,610	(17)%
3,890	193	(1916)%	863	TRANS-MAINT-MAINT OF MAINS	7,006	8,120	14 %
0	0	0 %	864	TRANS-MAINT COMP ST EQUIP	62	0	(100)%
1,910	2,604	27 %	865	TRANS-MAINT-MEAS & REG STATN EQUIP	30,861	39,700	22 %
0	0	0 %	867	TRANS-MAINT OTH EQUIPMENT	489	0	(100)%
207,744	172,251	(21)%	870	DISTRIB-OPT-SUPRV & ENGINEERING	2,128,482	1,606,647	(32)%
16,697	29,581	44 %	871	DISTRIB-OPT-LOAD DISPATHC & ODOR	282,773	365,348	23 %
0	0	0 %	872	DISTRIB-OPT-COMP STAT LABOR & EXPENSE	72	0	(100)%
163,791	98,562	(66)%	874	DISTRIB-OPT-MAINS & SERVICES	1,532,293	1,056,501	(45)%
7,825	10,337	24 %	875	DISTRIB-OPT-MEAS & REG STAT-GEN	93,204	103,121	10 %
20,693	22,113	6 %	876	DISTRIB-OPT-MEAS & REG STAT-IND	244,866	273,892	11 %
9,244	12,215	24 %	877	DISTRIB-OPT-MEAS & REG CITY GATE	174,523	188,874	8 %
112,358	132,141	15 %	878	DISTRIB-OPT-METER & HOUSE REG EXP	1,292,534	1,208,555	(7)%
67,982	83,554	19 %	879	DISTRIB-OPT-CUSTOMER INSTALL EXP	731,664	817,656	11 %
3,951	6,648	41 %	880	DISTRIB-OPT-OTHER EXP/DIST MAPS	44,801	55,046	19 %
110,773	106,910	(4)%	881	DISTRIB-OPT-RENTS/BLDG SRV	1,281,091	1,254,419	(2)%
44,492	48,514	8 %	885	DISTRIB-MAINT-SUPRV/ENGINEERING	414,818	460,686	10 %
495	653	24 %	886	DISTRIB-MAINT-STRUC & IMPROVEMENTS	15,027	22,267	33 %
12,110	8,305	(46)%	887	DISTRIB-MAINT-MAINT OF MAINS	65,287	103,242	37 %
3,308	610	(442)%	889	DISTRIB-MEAS & REG STAT - GEN	17,385	15,270	(14)%

ATMOS ENERGY CORPORATION
WESTERN KENTUCKY GAS COMPANY

CO DIV W

RESPONSIBILITY MANAGEMENT REPORT
BY NARUC-FERC ACCOUNT
FOR THE MONTH ENDED 09/29/98

THIS MONTH ACTUAL	THIS MONTH LAST YR	THIS MONTH FAV (UNFAV) COMPARED TO LST YR			YEAR TO DATE ACTUAL	YEAR TO DATE LAST YR	YEAR TO DATE FAV (UNFAV) COMPARED TO LST YR
3,962	4,290	8 %	890	DISTRIB-MEAS & REG STAT - IND	45,655	47,018	3 %
4,943	3,752	(32)%	891	DISTRIB-MEAS & REG STAT - CITY GATE	45,010	59,930	25 %
3,515	3,731	6 %	892	DISTRIB-MAINT OF SERVICE	26,246	22,469	(17)%
2,601	37,713	93 %	893	DISTRIB-MTRS & HOUSE REG	235,703	186,360	(26)%
521	154	(238)%	894	DISTRIB-MAINT-OTHER EQUIPMENT	8,364	9,034	7 %
7,366	27,934	74 %	901	CUS ACT EX-OPT-SUPERVISION	158,764	342,434	54 %
80,990	86,010	6 %	902	CUS ACT EX-OPT-METER READING EXP	1,038,732	1,053,793	1 %
6,121	173,082	96 %	903	CUS ACT EX-OPT-CUS REC/COLL EXP	669,663	2,051,670	67 %
140,507	(1,531)	(9277)%	904	CUS ACT EX-OPT-UNCOLL AC/DR/CR	706,442	501,885	(41)%
0	0	0 %	905	CUS ACT EX-OPT-MISC CUST AC EXP	20	0	(100)%
44,111	9,981	(342)%	909	CUS SRV EXP-OPT-SUPERVISION	279,920	106,085	(164)%
52,712	95,177	45 %	910	CUS SRV EXP-OPT-CUSTMR ASSIST	828,862	959,355	14 %
9,054	12,763	29 %	911	CUST SRV EXP-OPT-INFRM ADV EXP	63,008	86,229	27 %
1,193	783	(52)%	915	SALE PROMO EXP-OPT-SUPERVISION	9,000	3,963	(127)%
3,803	2,460	(55)%	916	SALE PROMO EXP-OPT-DEMO & SELL	67,730	52,238	(30)%
0	0	0 %	917	SALE PROMO EXP-OPT-PROMO ADV	1,097	0	(100)%
0	0	0 %	918	SALE PROMO EXP-OPT-MISC PROMO	3,753	5,281	29 %
0	0	0 %	920	ADM&GEN EX-OPT-ADM&GEN SALARY	11,100	0	(100)%
0	0	0 %	921	ADM&GEN EX-OPT-OFF SUPPLY & EXP	145	142	(2)%
0	0	0 %	923	ADM&GEN EX-OPT-OUTSIDE SRV EMP	3,186	0	(100)%
124,807	6,107	(1944)%	925	A&G EX-OPT INJR&DAMG INS DR/CR	231,448	91,662	(153)%
6,261	333,433	98 %	926	A&G EX-OPT-EMP WELF/PENS DR/CR	1,819,723	2,797,081	35 %
0	0	0 %	927	A&G EX-OPT-FRANCHISE REQUIREMENTS	14,862	19,323	23 %
350	200	(75)%	9302	A&G EX-OPT-MISC GENERAL EXP	38,890	36,795	(6)%
1,344,646	1,608,727	16 %		TOTAL NET EXPENSES	15,360,602	16,727,629	8 %

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 76
Witness: Betty Adams

Data Request:

Refer to Ms. Adams' testimony at page 10, line 17, where adjustments to Western's FY 1999 budget decreasing O & M expenses and increasing Shared Services expenses are discussed in regard to the United Cities Gas merger. Provide quantified schedules, referenced to Western's chart of accounts, with explanations of the cost shifts discussed, i.e., decreased number of employees by job classification to Western, new charges by Shared Services.

Response:

See response to DR 8. Much of the information necessary to develop the requested schedules is not available. Merger and reorganization tied to the various service improvement programs makes it impossible to compare pre- and post-merger costs by NARUC account.

For example, the accounting functions which were transferred to Shared Services as a result of the merger decreased within account 870 by $110,000 from FY98 to FY99, but the corresponding Shared Services amount in account 922 only increased by $45,000 due to WKG's lower allocation factor following the merger. Further complicating any comparison in account 870 is the transfer of certain office personnel into a newly created job classification of Operations Assistant, the costs of which are largely recorded in account 870 masked the decreased associated with the reduction in accounting personnel.

The only way to reasonably compare pre- and post-merger and re-organizational changes is on a total cost basis as reflected in DR 8.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 77
Witness: David H. Doggette

Data Request:

Refer to Ms. Adams' testimony at page 10, line 22, where adjustments to Western's FY 1999 budget from non-labor savings in the "proposed Gas Meter Performance Control Program" are referenced. Provide a detailed schedule with a calculation showing how these savings were determined.

Response:

The "proposed Gas Meter Performance Control Program" is in reference to Case No. 99-059 Western Kentucky Gas. (See Application, Volume 2, Tab 1, Gruber testimony, page 19) Western Kentucky Gas is currently requesting to implement a statistical sampling program for the periodic testing of meters. The current program is testing meters on a ten year cycle. The savings indicated, in Ms. Adams' testimony at page 10, line 22, is based on a reduction of annual testing of meters. The estimated savings is related to the difference in number of meters tested under the current plan and the number of meters that would be tested under the proposed plan. The commission has requested eight changes to the proposed plan. These changes will increase the number of meters tested thereby reducing the savings indicated. Western Kentucky Gas will not be able to provide the final cost savings estimate until the program is approved. See attached Schedule A "Analysis of Expected Annual Savings" which was filed with case No. 99-059.

WESTERN KENTUCKY GAS COMPANY
GAS METER PERFORMANCE CONTROL PROGRAM
ANALYSIS OF EXPECTED DIRECT ANNUAL COST SAVINGS (Note 1)

Estimated average annual reduction in number of meters tested			**9,000**
Based upon change from 10 year changeout to expected average life of 24 years and more than 157,815 meters in service			
Approximate average cost for periodic changing and testing each domestic size meter (Note 2):			
New meter	(4,000)	$49.82	
Repaired meter	(5,000)	$24.09	
Total			**$35.53**
Estimated average annual savings			**$319,730**

Note 1
The annual savings are a combination of reduced capital expenditures and reduced expenses. The annual savings reflect reductions in the growth of future operating costs not net reductions from current operating cost levels.

Note 2
Average quantity of meters either repaired, remanufactured, tested only, or retired per year is estimated at 5000 units with an average cost at $24.09.

Average quantity of new meters installed per year is estimated at 4000.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 78
Witness: Gruber

Data Request:

Refer to Ms. Adams' testimony at page 10, line 26 (Correction: question references line 22 in error), where adjustments to Western's FY 1999 budget from transferring the rates and regulatory vice-president position from the Shared Services staff is mentioned. Did similar job reclassifications occur with Western's gas distribution affiliates? If yes, give an explanation of the reasoning. If no, why not?

Response:

Yes, on October 1, 1998. This reclassification is consistent with Atmos' reorganization strategy of placing decision-making and control associated with key business unit programs, such as rates and regulatory affairs, directly into the business units. For further explanation, see pages 4-5 of Mr. Fischer's prepared direct testimony.

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 79
Witness: Betty Adams

Data Request:

Refer to Ms. Adams' testimony at page 13, lines 15 through 18, where the adjustments to Western's' "Shared Services" forecasted budget includes an adjustment for a "decrease in the labor portion of Atmos' administrative and general overheads, which is a capital expense."

a. Provide a description of these costs and a schedule of these costs, with reference to the accounts charged in the Shared Services forecasted budget.

b. Explain how these costs represent a capital expense as Atmos administrative and general overhead, but upon reclassification as a Shared Service expense become an operating and maintenance expense subject to recovery through customers' rates.

c. Were these costs similarly reclassified for Shared Services charges to Western's gas distribution affiliates? If yes, give an explanation of the reasoning. If no, why not?

Response:

a. Shared Services administrative and general overheads are a portion of the labor costs of the personnel that have duties that pertain to capital functions. Examples of this would be a person reviewing the project as well as an accounts payable clerk paying the invoices for capital projects. A schedule is not necessary. The $172,000 will decrease within Account 107 Construction Work in Progress.

b. The Shared Services O&M costs in calendar 2000 is increasing because direct capital spending is projected to decrease, causing a lower allocation to Shared Services overheads, which is a capital cost.

c. Yes. Shared Services overhead allocations will decrease in calendar 2000 in every business unit because total capital spending decreased.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 80
Witness: Adams

Data Request:

Provide the basis for the beginning of Western's FY 1999 budgeting process in quantitative form, i.e., prior year's budget, prior year's actual results, by Western's current chart of accounts.

a. Provide a listing of the known adjustments made at the beginning of Western's budgetary process, i.e., increase or decrease in employee numbers, reductions for expenses non-recurring in nature.
b. Provide a listing of the known adjustments made at the major decision-points of Western's budgetary process, i.e., increase or decrease in employee numbers, reductions for expenses non-recurring in nature, deferring or accelerating maintenance projects.

Response:

a. and b. As indicated on page 4, lines 27-28 of my testimony, Western's budget is zero-based and constructed from the bottom up. Consequently, there was no basis or baseline formally used by Western for constructing the FY 1999 O&M budget. Prior year's budget or actual results available at the time may have been used as a guideline by the functional managers or officers in the preparation of their inputs to the budget, but this was not required or formalized into our process.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 81
Witness: Adams

Data Request:

Provide the basis for the beginning of the Western's "Shared Services" FY 1999 budgeting process in quantitative form, i.e., prior year's budget, prior year's actual results, prior year service adjusted by changes in affiliated charges, by Western's current chart of accounts.

a. Provide a listing of the known adjustments made at the beginning of Shared Services' budgetary process, i.e., increase or decrease in employee numbers, reductions for expenses non-recurring in nature.
b. Provide a listing of the known adjustments made at the major decision-points of Shared Services' budgetary process, i.e., increase or decrease in employee numbers, reductions for expenses non-recurring in nature, deferring or accelerating projects.

Response:

a. and b. As indicated on page 4, lines 27-28 of my testimony, Western's budget is zero-based and constructed from the bottom up. Consequently, there was no basis or baseline formally used by Western for constructing the FY 1999 Shared Services O&M budget. Prior year's budget or actual results available at the time may have been used as a guideline by the functional managers or officers in the preparation of their inputs to the budget, but this was not required or formalized into our process

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 82
Witness: Betty Adams

Data Request:

Refer to Volume 2 of 10 of the Application, Tab 4, the Testimony of Betty M. Adams, page 3, which shows her sponsoring FR 10(10)(d) and FR 10(10)(f) and Volume 10 of 10, Tabs 4 and 6, which include FR 10(10)(d) and FR 10(10)(f). Provide a schedule of the rate-making adjustments for country club dues, promotional advertising and sales expenses, employee party and gift expenses and pension expense in reference to the "Detailed Adjustments" in Volume 10, FR 10(10)(d)2.1, FR 10(10)(d)2.2 and FR 10(10)(d)2.3 as applicable.

a. Provide the location of the above adjustments in FR 10(10)(d)1, with specific account number references.

b. Provide the location of the above adjustments in FR 10(10)(d)1, with specific account number references to the same schedule as previously requested to be resubmitted in Western's general ledger account number form.

Response:

There were no rate making adjustments made in FR 10(10)(d)2.1, FR 10(10)(d)2.2 or FR 10(10)(d)2.3. These schedules reflect only budgeting adjustments between the base and forecasted year. Please refer to FR 10(10)(c)2, Volume 10 of 10, Tab 3, for how the rate making adjustments were made.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 83 a and b
Witness: Betty L. Adams

Data Request:

Refer to Volume 2 of 10 of the Application, Tabs 2 and 4, the testimony of R. Earl Fischer and Betty L. Adams. To some extent, both witnesses address the issue of direct billed intercompany services and allocated service costs from Atmos' Shared Services Business Unit ("Shared Services") to Western and other Atmos business units.

a. Provide a detailed operating statement for Shared Services for FY 1997, 1998 and year to date FY 1999 actual, with detailed intercompany revenue accounts to reflect similar services provided by Shared Services for the Atmos operating divisions. Specifically, reference Shared Services' revenue accounts to Western's expense accounts by current chart of accounts. Provide the FY 1999 Shared Services budget and provide updates of FY 1999 actual data as it becomes available.
b. Provide contractual agreements between Western and Shared Services since 1997, with a schedule of expected service cost increases that are included in the determination of the base year or the forecasted year. Reference these service costs to Western's expense accounts by current chart of accounts.

Response:

a. There is not a detailed operating statement for Shared Services nor do they have revenues. Please see Volume 7 of 10, tab 3 for the monthly budget and actuals for FY 1999 through March. Attached is a copy of April's Financial Statements.
b. Attached are the contracts for FY 1999 as there were no contracts prior to this as this is a new procedure.

ATMOS ENERGY CORPORATION
Shared Services
For The Year-To-Date 4/30/99

	COMBINED DIRECT & BILLED										
DEPARTMENT	Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
ACCOUNTING:	3,824,816	941,363	729,471	325,377	1,245,619	568,110	0	0	0	14,875	0
BUSINESS DEVELOPMENT:	94,722	23,529	11,442	8,004	36,004	15,743	0	0	0	0	0
CALL CENTER:	3,865,425	1,206,013	769,220	309,234	904,510	676,449	0	0	0	0	0
EXECUTIVE:	3,671,300	994,989	623,137	321,275	1,091,174	605,940	0	0	0	34,786	0
GAS CONTROL:	284,189	34,979	47,649	14,741	124,514	62,306	0	0	0	0	0
GAS SUPPLY:	822,406	115,189	157,973	48,600	297,965	202,678	0	0	0	0	0
HUMAN RESOURCES:	5,486,133	1,336,113	1,222,072	534,078	1,083,739	1,122,980	0	0	0	187,149	0
INFORMATION TECHNOLOGY:	3,073,359	901,329	599,176	252,356	776,944	543,554	0	0	0	0	0
INTERNAL AUDIT:	322,619	96,177	62,175	25,906	78,043	56,023	0	0	0	4,294	0
INVESTOR RELATIONS:	874,557	180,435	167,233	80,976	291,337	134,666	0	0	0	19,909	0
LEGAL:	6,704,341	697,778	493,048	4,154,610	728,895	616,436	0	0	0	13,574	0
NEW BUSINESS VENTURES:	138,372	30,230	21,073	10,662	57,517	16,934	0	0	0	1,957	0
PLANNING & BUDGETING:	418,762	101,368	70,663	35,752	147,635	56,783	0	0	0	6,562	0
PRICE POLICY & ADMINISTRATION:	548,643	64,035	97,075	30,623	297,929	58,981	0	0	0	0	0
REGULATORY AFFAIRS:	198,352	21,682	29,300	12,501	113,774	21,096	0	0	0	0	0
TECHNICAL SERVICES:	114,301	25,992	15,796	10,299	44,097	17,774	80	183	69	0	11
TREASURY:	5,195,174	1,648,259	1,020,639	469,034	1,047,698	1,000,649	0	0	0	8,893	0
CONTROLLER MISCELLANEOUS:	(302,413)	(210,036)	(57,420)	(26,617)	37,536	(46,769)	0	0	0	893	
A&G CAPITALIZED:	(6,300,000)	(1,557,360)	(757,890)	(529,830)	(2,383,920)	(1,041,390)	(4,410)	(19,530)	(4,410)	0	(1,260)
MERGER & INTEGRATION	11,543,294	563,979	2,179,467	57,713	8,328,788	413,347	0	0	0	0	0
TOTAL OPERATIONS:	40,578,351	7,216,043	7,501,299	6,145,293	14,349,798	5,102,290	(4,330)	(19,347)	(4,341)	292,892	(1,249)
MAINTENANCE	391,066	96,672	47,045	32,889	147,979	64,643	274	1,212	274	0	78
DEPRECIATION	5,590,515	1,381,975	672,539	470,162	2,115,451	924,112	3,913	17,331	3,913	0	1,118
TAXES - OTHER	904,493	234,929	122,581	75,350	316,994	151,210	511	2,262	511	0	146
TOTAL	47,464,425	8,929,619	8,343,464	6,723,694	16,930,222	6,242,255	368	1,457	356	292,892	94

ATMOS ENERGY CORPORATION
Shared Services
For The Month Ended 4/30/99

		COMBINED DIRECT & BILLED										
DEPARTMENT		Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
0112900	VP & Controller	53,316	13,824	10,675	4,644	15,852	8,113	0	0	0	208	0
0113000	Director, Utility Accounting	15,279	3,962	3,059	1,331	4,543	2,325	0	0	0	60	0
0113100	General Accounting	47,362	12,280	9,483	4,125	14,082	7,207	0	0	0	185	0
0113200	Payroll Accounting	57,296	14,856	11,472	4,990	17,036	8,719	0	0	0	224	0
0113300	Accounts Payable	45,413	11,775	9,093	3,955	13,503	6,910	0	0	0	177	0
0113400	Accounting Systems	1,066	277	214	93	317	162	0	0	0	4	0
0113500	Assistant Controller, Utility Acctg	29,140	7,555	5,834	2,538	8,664	4,434	0	0	0	114	0
0113600	Plant Accounting	47,565	12,333	9,523	4,143	14,142	7,238	0	0	0	186	0
0113700	Gas Accounting	111,058	28,796	22,236	9,673	33,021	16,899	0	0	0	434	0
0113800	Customer Billing	8,379	2,173	1,678	730	2,491	1,275	0	0	0	33	0
0113900	Financial Reporting	80,307	20,823	16,079	6,994	23,878	12,220	0	0	0	314	0
0114600	Dallas Taxation	185,150	39,776	26,426	12,213	84,843	21,294	0	0	0	599	0
0118300	Dallas Stores	96	25	19	8	28	15	0	0	0	0	0
ACCOUNTING:		681,429	168,454	125,792	55,436	232,400	96,812	0	0	0	2,537	0
0056000	Business Development	8,456	2,100	1,021	715	3,214	1,405	0	0	0	0	0
BUSINESS DEVELOPMENT:		8,456	2,100	1,021	715	3,214	1,405	0	0	0	0	0
0120100	Amarillo Call Center	600,761	187,438	119,552	48,061	140,578	105,133	0	0	0	0	0
CALL CENTER:		600,761	187,438	119,552	48,061	140,578	105,133	0	0	0	0	0
0050500	Chairman, President & CEO	170,504	44,209	30,562	15,029	50,260	28,803	0	0	0	1,639	0
0050600	Business Process Initiative	142,932	42,864	18,274	11,142	47,247	22,399	0	0	0	1,005	0
0052100	Dallas Operations	57,634	14,113	10,827	5,353	17,241	9,523	0	0	0	577	0
0052500	Utility Services	4,413	1,164	832	407	1,222	739	0	0	0	48	0
0054700	Chief Financial Officer	130,172	34,341	24,548	12,013	36,038	21,806	0	0	0	1,426	0
EXECUTIVE:		505,655	136,692	85,044	43,944	152,008	83,270	0	0	0	4,696	0
0051700	Corporate Gas Control	33,197	4,086	5,515	1,722	14,666	7,208	0	0	0	0	0
GAS CONTROL:		33,197	4,086	5,515	1,722	14,666	7,208	0	0	0	0	0
0051500	Interstate Gas Supply	60,917	8,465	11,882	3,567	22,069	14,934	0	0	0	0	0
0051600	Intrastate Gas Supply	32,736	4,856	6,127	1,913	11,833	8,007	0	0	0	0	0
0051900	Gas Supply	25,027	3,602	4,709	1,470	9,093	6,154	0	0	0	0	0
GAS SUPPLY:		118,681	16,922	22,718	6,950	42,995	29,095	0	0	0	0	0
0056100	Professional Development	8,160	2,030	1,547	653	2,292	1,281	0	0	0	358	0
0116900	Executive Compensation	43,993	15,464	8,133	7,283	4,167	8,231	0	0	0	715	0
0117000	Dallas EAPC	7,251	1,850	1,410	595	1,902	1,167	0	0	0	326	0
0117100	Corporate Services	12	3	2	1	3	2	0	0	0	1	0
0117200	Compensation & Employment	29,370	7,099	5,664	2,319	8,652	4,574	0	0	0	1,063	0
0117300	Human Resources - VP	21,499	5,487	4,180	1,764	5,639	3,462	0	0	0	968	0
0117400	Employee & Labor Relations	3,384	864	658	278	888	545	0	0	0	152	0
0117500	Employee Benefits	180,930	45,075	31,263	17,189	50,373	29,790	0	0	0	7,239	0
0117800	Employee Communications	15,447	3,942	3,003	1,267	4,052	2,487	0	0	0	695	0
0117900	Facilities	7,429	1,896	1,445	609	1,949	1,196	0	0	0	335	0
0118100	Employee Development	28,296	9,178	5,009	2,100	6,735	4,122	0	0	0	1,153	0
0119000	Employee Relocation Expense	64,673	8,331	8,366	2,451	7,837	36,343	0	0	0	1,345	0
0119210	Management Incentive/Variable Pay	0	0	0	0	0	0	0	0	0	0	0
0119400	Treasury - Worker's Comp	(1,830)	(467)	(356)	(150)	(480)	(295)	0	0	0	(82)	0
0119500	Human Resources - Benefits	296,446	75,619	57,721	24,305	77,749	47,710	0	0	0	13,341	0
0119600	Retirement Costs	(19,515)	(15,791)	13,401	3,833	(16,353)	(3,825)	0	0	0	(779)	0
HUMAN RESOURCES:		685,547	160,580	141,447	64,496	155,404	136,790	0	0	0	26,830	0

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ATMOS ENERGY CORPORATION
Shared Services
For The Month Ended 4/30/99

DEPARTMENT		Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
		COMBINED DIRECT & BILLED										
0115000	Information Services	25,523	7,478	4,977	2,093	6,457	4,518	0	0	0	0	0
0115100	Production Services	211,402	61,941	41,223	17,335	53,485	37,418	0	0	0	0	0
0115300	Information Systems	94,713	27,751	18,469	7,766	23,962	16,764	0	0	0	0	0
0115400	Information Support	69,921	20,487	13,635	5,734	17,690	12,376	0	0	0	0	0
0115500	Office Equipment	9,276	2,718	1,809	761	2,347	1,642	0	0	0	0	0
0115600	Telecommunication Services	20,144	5,902	3,928	1,652	5,096	3,566	0	0	0	0	0
INFORMATION TECHNOLOGY:		430,979	126,277	84,041	35,340	109,038	76,283	0	0	0	0	0
0116400	Internal Audit	34,084	10,161	6,569	2,737	8,245	5,919	0	0	0	454	0
INTERNAL AUDIT:		34,084	10,161	6,569	2,737	8,245	5,919	0	0	0	454	0
0054900	Investor Relations	71,273	14,705	13,629	6,599	23,743	10,975	0	0	0	1,623	0
0117700	Corporate Communications	41,946	8,654	8,021	3,884	13,973	6,459	0	0	0	955	0
0052400	Public Affairs	90	19	17	8	30	14	0	0	0	2	0
INVESTOR RELATIONS:		113,309	23,377	21,667	10,491	37,746	17,448	0	0	0	2,579	0
0052000	Legal	110,395	24,948	20,583	14,423	33,204	16,784	0	0	0	453	0
0052050	General Liability	153,816	40,000	40,000	10,000	30,000	33,816	0	0	0	0	0
0051400	Contract Administration	12,013	2,910	1,852	3,246	2,309	1,659	0	0	0	38	0
0052200	Governmental Affairs	10,569	3,011	1,452	2,195	1,654	2,142	0	0	0	116	0
0057900	Corporate Secretary	114,976	34,323	22,345	9,214	28,219	20,156	0	0	0	719	0
0119300	Outside Directors Retirement Cost	120,574	30,613	22,869	12,826	31,702	21,054	0	0	0	1,510	0
0118200	Central Records	19,866	5,931	3,861	1,592	4,876	3,483	0	0	0	124	0
LEGAL:		542,209	141,735	112,961	53,497	131,963	99,094	0	0	0	2,959	0
0054600	New Business Ventures	8,708	2,130	1,485	751	3,012	1,193	0	0	0	138	0
NEW BUSINESS VENTURES:		8,708	2,130	1,485	751	3,012	1,193	0	0	0	138	0
0054400	Financial & Strategic Planning	62,366	15,097	10,524	5,325	21,987	8,457	0	0	0	977	0
0054500	Business Strategies & Competitive Intelligence	0	0	0	0	0	0	0	0	0	0	0
0114300	Budget & Planning	3,087	747	521	264	1,088	419	0	0	0	48	0
PLANNING & BUDGETING:		65,453	15,844	11,045	5,588	23,076	8,875	0	0	0	1,026	0
0054000	Price Policy & Administration - V.P.	0	0	0	0	0	0	0	0	0	0	0
0054000	Price Policy & Administration	59,211	7,466	8,526	3,420	34,027	5,772	0	0	0	0	0
PRICE POLICY & ADMINISTRATION:		59,211	7,466	8,526	3,420	34,027	5,772	0	0	0	0	0
0054100	Regulatory Affairs	26,251	2,914	3,938	1,680	14,884	2,835	0	0	0	0	0
REGULATORY AFFAIRS:		26,251	2,914	3,938	1,680	14,884	2,835	0	0	0	0	0
0056200	Technical Services	17,280	3,930	2,388	1,557	6,667	2,687	12	28	10	0	2
TECHNICAL SERVICES:		17,280	3,930	2,388	1,557	6,667	2,687	12	28	10	0	2
0114500	Dallas Treasury	70,226	19,889	13,583	5,771	18,179	12,035	0	0	0	769	0
0114700	Dallas Risk Management	132,002	28,929	26,372	6,940	48,727	20,505	0	0	0	528	0
0114800	Dallas Treasurer	32,118	9,085	6,218	2,642	8,312	5,509	0	0	0	352	0
0115200	Mass Mail	233,898	90,366	63,558	25,294	0	54,680	0	0	0	0	0
0117600	Purchasing	16,493	4,107	2,408	1,699	5,080	3,200	0	0	0	0	0
0118000	Remittance Processing	450,683	149,208	80,737	36,553	104,019	80,166	0	0	0	0	0
0118500	Mail & Supply	18,548	4,737	2,717	1,956	5,548	3,591	0	0	0	0	0
0118909	Fleet Administration	10	2	1	1	3	2	0	0	0	0	0
0118600	Purchasing & Stores	10,615	2,643	1,550	1,093	3,269	2,059	0	0	0	0	0

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ATMOS ENERGY CORPORATION
Shared Services
For The Month Ended 4/30/99

DEPARTMENT	Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
	COMBINED DIRECT & BILLED										
TREASURY:	964,593	308,966	197,144	81,950	193,136	181,748	0	0	0	1,649	0
0119800 Atmos - Overhead Capitalized	(900,000)	(222,480)	(108,270)	(75,690)	(340,560)	(148,770)	(630)	(2,790)	(630)	0	(180)
A&G CAPITALIZED:	(900,000)	(222,480)	(108,270)	(75,690)	(340,560)	(148,770)	(630)	(2,790)	(630)	0	(180)
0119200 Controller Miscellaneous	94,859	30,266	10,571	9,727	26,867	16,994	0	0	0	436	0
CONTROLLER MISCELLANEOUS:	94,859	30,266	10,571	9,727	26,867	16,994	0	0	0	436	0
0119220 Merger & Integration	737,696	36,045	137,366	3,688	534,182	26,415	0	0	0	0	0
MERGER & INTEGRATION	737,696	36,045	137,366	3,688	534,182	26,415	0	0	0	0	0
TOTAL OPERATIONS:	4,828,358	1,162,902	990,517	356,059	1,523,548	756,206	(618)	(2,762)	(620)	43,304	(178)
MAINTENANCE	31,765	7,852	3,821	2,671	12,020	5,251	22	98	22	0	6
DEPRECIATION	808,645	199,897	97,280	68,007	305,991	133,669	566	2,507	566	0	162
TAXES - OTHER	98,385	26,039	13,922	8,165	33,400	16,520	50	223	50	0	14
TOTAL	5,767,153	1,396,691	1,105,541	434,903	1,874,959	911,646	21	66	19	43,304	4

ATMOS ENERGY CORPORATION
Shared Services
For The Year-To-Date 4/30/99

COMBINED DIRECT & BILLED

DEPARTMENT		Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
0112900	VP & Controller	466,771	121,027	93,457	40,654	138,784	71,027	0	0	0	1,822	0
0113000	Director, Utility Accounting	131,539	34,106	26,337	11,456	39,110	20,016	0	0	0	514	0
0113100	General Accounting	377,761	97,948	75,635	32,901	112,319	57,483	0	0	0	1,475	0
0113200	Payroll Accounting	373,481	96,832	74,726	32,526	111,100	56,842	0	0	0	1,455	0
0113300	Accounts Payable	301,731	78,234	60,413	26,280	89,713	45,914	0	0	0	1,178	0
0113400	Accounting Systems	7,708	1,998	1,543	671	2,292	1,173	0	0	0	30	0
0113500	Assistant Controller, Utility Acctg	191,646	49,691	38,371	16,692	56,982	29,162	0	0	0	748	0
0113600	Plant Accounting	249,336	64,649	49,922	21,716	74,134	37,941	0	0	0	973	0
0113700	Gas Accounting	755,424	195,870	151,251	65,794	224,608	114,951	0	0	0	2,949	0
0113800	Customer Billing	28,362	7,354	5,679	2,470	8,433	4,316	0	0	0	111	0
0113900	Financial Reporting	412,460	106,945	82,583	35,924	122,635	62,763	0	0	0	1,610	0
0114600	Dallas Taxation	531,272	87,403	70,089	38,526	266,305	66,930	0	0	0	2,019	0
0118300	Dallas Stores	(2,675)	(694)	(536)	(233)	(795)	(407)	0	0	0	(10)	0
ACCOUNTING:		3,824,816	941,363	729,471	325,377	1,245,619	568,110	0	0	0	14,875	0
0056000	Business Development	94,722	23,529	11,442	8,004	36,004	15,743	0	0	0	0	0
BUSINESS DEVELOPMENT:		94,722	23,529	11,442	8,004	36,004	15,743	0	0	0	0	0
0120100	Amarillo Call Center	3,865,425	1,206,013	769,220	309,234	904,510	676,449	0	0	0	0	0
CALL CENTER:		3,865,425	1,206,013	769,220	309,234	904,510	676,449	0	0	0	0	0
0050500	Chairman, President & CEO	1,657,183	431,838	301,412	148,012	480,037	279,328	0	0	0	16,557	0
0050600	Business Process Initiative	946,696	283,908	121,038	73,799	312,935	148,357	0	0	0	6,659	0
0052100	Dallas Operations	323,969	83,111	60,486	30,855	92,376	53,715	0	0	0	3,427	0
0052500	Utility Services	33,718	8,895	6,359	3,112	9,335	5,648	0	0	0	369	0
0054700	Chief Financial Officer	709,734	187,237	133,842	65,497	196,492	118,892	0	0	0	7,774	0
EXECUTIVE:		3,671,300	994,989	623,137	321,275	1,091,174	605,940	0	0	0	34,786	0
0051700	Corporate Gas Control	284,189	34,979	47,649	14,741	124,514	62,306	0	0	0	0	0
GAS CONTROL:		284,189	34,979	47,649	14,741	124,514	62,306	0	0	0	0	0
0051500	Interstate Gas Supply	409,044	56,751	79,166	23,916	148,009	101,201	0	0	0	0	0
0051600	Intrastate Gas Supply	234,939	33,070	44,889	13,803	85,391	57,785	0	0	0	0	0
0051900	Gas Supply	178,423	25,369	33,918	10,880	64,565	43,692	0	0	0	0	0
GAS SUPPLY:		822,406	115,189	157,973	48,600	297,965	202,678	0	0	0	0	0
0056100	Professional Development	133,518	28,639	21,820	9,205	50,730	18,070	0	0	0	5,053	0
0116900	Executive Compensation	247,695	51,818	60,259	43,259	29,804	57,438	0	0	0	5,116	0
0117000	Dallas EAPC	14,008	3,574	2,723	1,149	3,674	2,255	0	0	0	631	0
0117100	Corporate Services	408	104	79	33	107	66	0	0	0	18	0
0117200	Compensation & Employment	178,737	46,275	35,213	14,791	45,851	29,158	0	0	0	7,448	0
0117300	Human Resources - VP	182,535	46,583	35,492	14,973	47,877	29,392	0	0	0	8,219	0
0117400	Employee & Labor Relations	49,270	12,574	9,580	4,042	12,923	7,933	0	0	0	2,218	0
0117500	Employee Benefits	633,835	209,215	98,054	52,643	145,402	108,181	0	0	0	20,341	0
0117800	Employee Communications	115,977	29,597	22,550	9,513	30,419	18,674	0	0	0	5,222	0
0117900	Facilities	105,442	26,909	20,502	8,649	27,656	16,978	0	0	0	4,747	0
0118100	Employee Development	203,478	55,789	38,618	16,360	51,167	32,764	0	0	0	8,780	0
0119000	Employee Relocation Expense	626,451	119,331	159,919	8,556	63,175	270,774	0	0	0	4,696	0
0119210	Management Incentive/Variable Pay	889,598	267,726	219,639	120,273	37,040	153,076	0	0	0	91,844	0
0119400	Treasury - Worker's Comp	(1,630)	447	(365)	(90)	(1,533)	(4)	0	0	0	(85)	0
0119500	Human Resources - Benefits	112,909	3,303	6,921	4,116	89,772	7,318	0	0	0	1,480	0
0119600	Retirement Costs	1,993,903	434,228	491,068	226,606	449,675	370,907	0	0	0	21,420	0
HUMAN RESOURCES:		5,486,133	1,336,113	1,222,072	534,078	1,083,739	1,122,980	0	0	0	187,149	0

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ATMOS ENERGY CORPORATION
Shared Services
For The Year-To-Date 4/30/99

DEPARTMENT	COMBINED DIRECT & BILLED Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
0115000 Information Services	172,895	50,658	33,715	14,177	43,743	30,602	0	0	0	0	0
0115100 Production Services	1,414,297	414,389	275,788	115,972	357,817	250,330	0	0	0	0	0
0115300 Information Systems	592,941	173,732	115,623	48,621	150,014	104,951	0	0	0	0	0
0115400 Information Support	640,499	187,666	124,897	52,521	162,046	113,368	0	0	0	0	0
0115500 Office Equipment	70,830	21,594	13,666	6,150	17,310	12,110	0	0	0	0	0
0115600 Telecommunication Services	181,897	53,290	35,486	14,914	46,015	32,192	0	0	0	0	0
INFORMATION TECHNOLOGY:	3,073,359	901,329	599,176	252,356	776,944	543,554	0	0	0	0	0
0116400 Internal Audit	322,619	96,177	62,175	25,906	78,043	56,023	0	0	0	4,294	0
INTERNAL AUDIT:	322,619	96,177	62,175	25,906	78,043	56,023	0	0	0	4,294	0
0054900 Investor Relations	633,743	130,752	121,184	58,679	211,116	97,585	0	0	0	14,427	0
0117700 Corporate Communications	237,479	48,996	45,411	21,988	79,110	36,568	0	0	0	5,406	0
0052400 Public Affairs	3,334	688	638	309	1,111	513	0	0	0	76	0
INVESTOR RELATIONS:	874,557	180,435	167,233	80,976	291,337	134,666	0	0	0	19,909	0
0052000 Legal	1,583,200	237,426	203,728	599,763	373,292	166,651	0	0	0	2,340	0
0052050 General Liability	3,789,491	88,833	40,000	3,411,232	31,500	217,926	0	0	0	0	0
0051400 Contract Administration	85,038	20,597	13,107	22,980	16,342	11,746	0	0	0	266	0
0052200 Governmental Affairs	69,096	19,684	9,495	14,347	10,812	14,000	0	0	0	757	0
0057900 Corporate Secretary	622,149	185,727	120,910	49,860	152,695	109,068	0	0	0	3,889	0
0119300 Outside Directors Retirement Cost	454,395	115,368	86,184	48,336	119,472	79,344	0	0	0	5,691	0
0118200 Central Records	100,972	30,143	19,623	8,092	24,782	17,701	0	0	0	631	0
LEGAL:	6,704,341	697,778	493,048	4,154,610	728,895	616,436	0	0	0	13,574	0
0054600 New Business Ventures	138,372	30,230	21,073	10,662	57,517	16,934	0	0	0	1,957	0
NEW BUSINESS VENTURES:	138,372	30,230	21,073	10,662	57,517	16,934	0	0	0	1,957	0
0054400 Financial & Strategic Planning	396,617	96,007	66,926	33,861	139,828	53,780	0	0	0	6,215	0
0054500 Business Strategies & Competitive Intelligence	361	87	61	31	127	49	0	0	0	6	0
0114300 Budget & Planning	21,783	5,273	3,676	1,860	7,680	2,954	0	0	0	341	0
PLANNING & BUDGETING:	418,762	101,368	70,663	35,752	147,635	56,783	0	0	0	6,562	0
0054000 Price Policy & Administration	548,643	64,035	97,075	30,623	297,929	58,981	0	0	0	0	0
PRICE POLICY & ADMINISTRATION:	548,643	64,035	97,075	30,623	297,929	58,981	0	0	0	0	0
0054100 Regulatory Affairs	198,352	21,682	29,300	12,501	113,774	21,096	0	0	0	0	0
REGULATORY AFFAIRS:	198,352	21,682	29,300	12,501	113,774	21,096	0	0	0	0	0
0056200 Technical Services	114,301	25,992	15,796	10,299	44,097	17,774	80	183	69	0	11
TECHNICAL SERVICES:	114,301	25,992	15,796	10,299	44,097	17,774	80	183	69	0	11
0114500 Dallas Treasury	353,492	97,447	68,046	28,314	95,521	60,393	0	0	0	3,771	0
0114700 Dallas Risk Management	913,041	198,674	164,041	69,998	335,280	141,797	0	0	0	3,251	0
0114800 Dallas Treasurer	170,907	48,345	33,087	14,058	44,230	29,315	0	0	0	1,872	0
0115200 Mass Mail	1,442,481	568,343	370,088	157,468	0	346,581	0	0	0	0	0
0117600 Purchasing	132,796	33,066	19,388	13,678	40,901	25,762	0	0	0	0	0
0118000 Remittance Processing	1,970,978	648,936	334,875	163,506	467,840	355,821	0	0	0	0	0
0118500 Mail & Supply	134,757	34,345	19,912	14,109	40,295	26,096	0	0	0	0	0
0118909 Fleet Administration	162	40	24	17	50	32	0	0	0	0	0
0118600 Purchasing & Stores	76,560	19,063	11,178	7,886	23,580	14,853	0	0	0	0	0
TREASURY:	5,195,174	1,648,259	1,020,639	469,034	1,047,698	1,000,649	0	0	0	8,893	0

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ATMOS ENERGY CORPORATION
Shared Services
For The Year-To-Date 4/30/99

COMBINED DIRECT & BILLED

DEPARTMENT	Total	Energas	GGC	Trans La	UCG	WKG	Egasco	Enermart	TLIG	Propane	WKGR
0119200 Controller Miscellaneous	(302,413)	(210,036)	(57,420)	(26,617)	37,536	(46,769)	0	0	0	893	0
CONTROLLER MISCELLANEOUS:	(302,413)	(210,036)	(57,420)	(26,617)	37,536	(46,769)	0	0	0	893	
0119800 Atmos - Overhead Capitalized	(6,300,000)	(1,557,360)	(757,890)	(529,830)	(2,383,920)	(1,041,390)	(4,410)	(19,530)	(4,410)	0	(1,260)
A&G CAPITALIZED:	(6,300,000)	(1,557,360)	(757,890)	(529,830)	(2,383,920)	(1,041,390)	(4,410)	(19,530)	(4,410)	0	(1,260)
0119220 Merger & Integration	11,543,294	563,979	2,179,467	57,713	8,328,788	413,347	0	0	0	0	0
MERGER & INTEGRATION	11,543,294	563,979	2,179,467	57,713	8,328,788	413,347	0	0	0	0	0
TOTAL OPERATIONS:	40,578,351	7,216,043	7,501,299	6,145,293	14,349,798	5,102,290	(4,330)	(19,347)	(4,341)	292,892	(1,249)
MAINTENANCE	391,066	96,672	47,045	32,889	147,979	64,643	274	1,212	274	0	78
DEPRECIATION	5,590,515	1,381,975	672,539	470,162	2,115,451	924,112	3,913	17,331	3,913	0	1,118
TAXES - OTHER	904,493	234,929	122,581	75,350	316,994	151,210	511	2,262	511	0	146
TOTAL	47,464,425	8,929,619	8,343,464	6,723,694	16,930,222	6,242,255	368	1,457	356	292,892	94

MOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Month Ended 4/30/99

Department Name	FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
EXECUTIVE:	505,655	304,123	201,532	300,254	205,401
FINANCE:					
ACCOUNTING	681,429	363,615	317,814	402,244	279,185
INFORMATION TECHNOLOGY	430,979	535,779	(104,800)	372,076	58,903
INTERNAL AUDIT	34,084	58,419	(24,335)	-	34,084
INVESTOR RELATIONS	113,309	185,889	(72,580)	77,148	36,161
NEW BUSINESS VENTURES	8,708	-	8,708	5,236	3,472
PLANNING & BUDGETING	65,453	68,229	(2,776)	62,407	3,046
PRICE POLICY & ADMINISTRATION	59,211	164,302	(105,091)	-	59,211
REGULATORY AFFAIRS	26,251	64,051	(37,800)	-	26,251
TREASURY:	964,593	1,110,105	(145,512)	337,628	626,965
TOTAL FINANCE:	2,384,017	2,550,389	(166,372)	1,256,739	1,127,278
OPERATIONS:					
BUSINESS DEVELOPMENT	8,456	-	8,456	36,361	(27,905)
CALL CENTER	600,761	663,846	(63,085)	774	599,987
GAS SUPPLY & GAS CONTROL	151,877	176,370	(24,493)	190,600	(38,723)
TECHNICAL SERVICES	17,280	13,030	4,250	20,295	(3,015)
TOTAL OPERATIONS:	778,375	853,246	(74,871)	248,030	530,345
HUMAN RESOURCES:	685,547	998,961	(313,414)	876,542	(190,995)
LEGAL:	542,209	364,257	177,952	382,121	160,088
CONTROLLER MISCELLANEOUS:	94,859	-	94,859	29,178	65,681
ATMOS OVERHEAD CAPITALIZED:	(900,000)	(884,920)	(15,080)	(881,000)	(19,000)
MERGER & INTEGRATION:	495,700	345,255	150,445	-	495,700
TOTAL O&M	4,586,362	4,531,311	55,051	2,211,864	2,374,498
DEPRECIATION	808,645	639,000	169,645	270,919	537,726
TAXES - OTHER	98,385	72,500	25,885	69,777	28,608
TOTAL	5,493,392	5,242,811	250,581	2,552,560	2,940,832

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Year-To-Date 4/30/99

Department Name	FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
EXECUTIVE:	3,671,300	2,086,513	1,584,787	1,901,559	1,769,741
FINANCE:					
ACCOUNTING	3,824,816	2,604,031	1,220,785	2,275,970	1,548,846
INFORMATION TECHNOLOGY	3,073,359	3,127,124	(53,765)	3,824,523	(751,164)
INTERNAL AUDIT	322,619	407,274	(84,655)	-	322,619
INVESTOR RELATIONS	874,557	1,294,718	(420,161)	861,290	13,267
NEW BUSINESS VENTURES	138,372	-	138,372	5,236	133,136
PLANNING & BUDGETING	418,762	479,909	(61,147)	313,436	105,326
PRICE POLICY & ADMINISTRATION	548,643	1,191,761	(643,118)	-	548,643
REGULATORY AFFAIRS	198,352	446,767	(248,415)	-	198,352
TREASURY:	5,195,173	7,888,698	(2,693,525)	2,248,270	2,946,903
TOTAL FINANCE:	14,594,652	17,440,282	(2,845,630)	9,528,725	5,065,927
OPERATIONS:					
BUSINESS DEVELOPMENT	94,722	-	94,722	330,394	(235,672)
CALL CENTER	3,865,425	4,646,922	(781,497)	35,417	3,830,008
GAS SUPPLY & GAS CONTROL	1,106,595	1,223,860	(117,265)	1,186,440	(79,845)
TECHNICAL SERVICES	114,301	89,260	25,041	249,111	(134,810)
TOTAL OPERATIONS:	5,181,044	5,960,042	(778,998)	1,801,362	3,379,682
HUMAN RESOURCES:	5,486,131	7,061,266	(1,575,135)	4,129,205	1,356,926
LEGAL:	6,704,341	2,571,880	4,132,461	3,764,433	2,939,908
CONTROLLER MISCELLANEOUS:	(302,413)	-	(302,413)	(1,248)	(301,165)
ATMOS OVERHEAD CAPITALIZED:	(6,300,000)	(6,194,440)	(105,560)	(6,167,000)	(133,000)
MERGER & INTEGRATION:	3,469,774	2,416,765	1,053,009	-	3,469,774
TOTAL O&M	32,504,828	31,342,308	1,162,520	14,957,036	17,547,792
DEPRECIATION	5,590,515	4,473,000	1,117,515	1,897,035	3,693,480
TAXES - OTHER	904,493	507,500	396,993	586,900	317,593
TOTAL	38,999,836	36,322,808	2,677,028	17,440,971	21,558,864

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Month Ended 4/30/99

Department Name		FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
EXECUTIVE:						
0050500	Chairman, President & CEO	170,504	146,497	24,007	152,952	17,552
0050600	Business Process Initiative	142,932	-	142,932	-	142,932
0052100	Dallas Operations	57,634	36,087	21,547	55,503	2,131
0052500	Utility Services	4,413	-	4,413	5,876	(1,463)
0054700	Chief Financial Officer	130,172	121,539	8,633	85,923	44,249
EXECUTIVE:		505,655	304,123	201,532	300,254	205,401
FINANCE:						
0112900	VP & Controller	53,316	-	53,316	81,090	(27,774)
0113000	Director, Utility Accounting	15,279	16,522	(1,243)	10,918	4,361
0113100	General Accounting	47,362	51,797	(4,435)	43,766	3,596
0113200	Payroll Accounting	57,296	44,542	12,754	54,517	2,779
0113300	Accounts Payable	45,413	38,678	6,735	20,263	25,150
0113400	Accounting Systems	1,066	-	1,066	957	109
0113500	Assistant Controller, Utility Acctg	29,140	-	29,140	5,845	23,295
0113600	Plant Accounting	47,565	33,073	14,492	38,385	9,180
0113700	Gas Accounting	111,058	86,741	24,317	78,088	32,970
0113800	Customer Billing	8,379	-	8,379	7,859	520
0113900	Financial Reporting	80,307	45,703	34,604	27,427	52,880
0114600	Dallas Taxation	185,150	46,559	138,591	32,960	152,190
0118300	Dallas Stores	96	-	96	169	(73)
ACCOUNTING		681,429	363,615	317,814	402,244	279,185
0115000	Information Services	25,523	29,694	(4,171)	(161,584)	187,107
0115100	Production Services	211,402	272,588	(61,186)	136,295	75,107
0115300	Information Systems	94,713	130,305	(35,592)	290,162	(195,449)
0115400	Information Support	69,921	72,439	(2,518)	71,505	(1,584)
0115500	Office Equipment	9,276	4,250	5,026	32,372	(23,096)
0115600	Telecommunication Services	20,144	26,503	(6,359)	3,326	16,818
INFORMATION TECHNOLOGY		430,979	535,779	(104,800)	372,076	58,903
0116400	Internal Audit	34,084	58,419	(24,335)	-	34,084
INTERNAL AUDIT		34,084	58,419	(24,335)	-	34,084
0054900	Investor Relations	71,273	127,742	(56,469)	-	71,273
0052400	Public Affairs	90	-	90	76,163	(76,073)
0117700	Corporate Communications	41,946	58,147	(16,201)	985	40,961
INVESTOR RELATIONS		113,309	185,889	(72,580)	77,148	36,161

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Month Ended 4/30/99

Department Name		FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
0054200	Retail Services	-	-	-	-	-
0054600	New Business Ventures	8,708	-	8,708	5,236	3,472
NEW BUSINESS VENTURES		8,708	-	8,708	5,236	3,472
0054400	Financial & Strategic Planning	62,366	68,229	(5,863)	-	62,366
0054500	Business Strategies & Competitive Intelligence	-	-	-	67,503	(67,503)
0114300	Budget & Planning	3,087	-	3,087	(5,096)	8,183
PLANNING & BUDGETING		65,453	68,229	(2,776)	62,407	3,046
0054000	Price Policy & Administration	59,211	164,302	(105,091)	-	59,211
PRICE POLICY & ADMINISTRATION		59,211	164,302	(105,091)	-	59,211
0054100	Regulatory Affairs	26,251	64,051	(37,800)	-	26,251
REGULATORY AFFAIRS		26,251	64,051	(37,800)	-	26,251
0114500	Dallas Treasury	70,226	46,172	24,054	-	70,226
0114700	Dallas Risk Management	132,002	275,065	(143,063)	28,073	103,929
0114800	Dallas Treasurer	32,118	21,013	11,105	170,139	(138,021)
0115200	Mass Mail	233,898	-	233,898	15,096	218,802
0117600	Purchasing	16,493	16,873	(380)	13,538	2,955
0118000	Remittance Processing	450,683	710,616	(259,933)	81,391	369,292
0118500	Mail & Supply	18,548	19,370	(822)	19,148	(600)
0118600	Purchasing & Stores	10,615	11,832	(1,217)	10,209	406
0118909	Fleet Administration	10	9,164	(9,154)	34	(24)
TREASURY:		964,593	1,110,105	(145,512)	337,628	626,965
TOTAL FINANCE:		2,384,017	2,550,389	(166,372)	1,256,739	1,127,278
OPERATIONS:						
0056000	Business Development	8,456	-	8,456	36,361	(27,905)
BUSINESS DEVELOPMENT		8,456	-	8,456	36,361	(27,905)
0120100	Amarillo Call Center	600,761	663,846	(63,085)	774	599,987
CALL CENTER		600,761	663,846	(63,085)	774	599,987
0051500	Interstate Gas Supply	60,917	60,215	702	58,920	1,997
0051600	Intrastate Gas Supply	32,736	43,035	(10,299)	37,590	(4,854)
0051700	Corporate Gas Control	33,197	46,075	(12,878)	68,570	(35,373)
0051900	Gas Supply	25,027	27,045	(2,018)	25,520	(493)

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Month Ended 4/30/99

Department Name		FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
GAS SUPPLY & GAS CONTROL		151,877	176,370	(24,493)	190,600	(38,723)
0056200	Technical Services	17,280	13,030	4,250	20,295	(3,015)
TECHNICAL SERVICES		17,280	13,030	4,250	20,295	(3,015)
TOTAL OPERATIONS:		778,375	853,246	(74,871)	248,030	530,345
HUMAN RESOURCES:						
0056100	Professional Development	8,160	23,804	(15,644)	3,582	4,578
0116900	Executive Compensation	43,993	57,623	(13,630)	-	43,993
0117000	Dallas EAPC	7,251	-	7,251	-	7,251
0117100	Corporate Services	12	-	12	2,816	(2,804)
0117200	Compensation & Employment	29,370	41,872	(12,502)	42,942	(13,572)
0117300	Human Resources - VP	21,499	24,025	(2,526)	20,433	1,066
0117400	Employee & Labor Relations	3,384	10,293	(6,909)	9,297	(5,913)
0117500	Employee Benefits	180,930	63,389	117,541	151,808	29,122
0117800	Employee Communications	15,447	36,530	(21,083)	9,570	5,877
0117900	Facilities	7,429	13,902	(6,473)	16,484	(9,055)
0118100	Employee Development	28,296	74,355	(46,059)	26,402	1,894
0119000	Employee Relocation Expense	64,673	67,919	(3,246)	54,627	10,046
0119210	Management Incentive/Variable Pay	-	191,666	(191,666)	116,667	(116,667)
0119400	Treasury - Worker's Comp	(1,830)	-	(1,830)	29	(1,859)
0119500	Human Resources - Benefits	296,446	-	296,446	105,789	190,657
0119600	Retirement Costs	(19,515)	393,583	(413,098)	316,096	(335,611)
HUMAN RESOURCES:		685,547	998,961	(313,414)	876,542	(190,995)
LEGAL:						
0052000	Legal	110,395	189,103	(78,708)	270,372	(159,977)
0052050	General Liability Accrual	153,816	-	153,816	-	153,816
0051400	Contract Administration	12,013	13,047	(1,034)	9,195	2,818
0052200	Governmental Affairs	10,569	32,486	(21,917)	9,727	842
0057900	Corporate Secretary	114,976	108,445	6,531	59,289	55,687
0119300	Outside Directors Retirement Cost	120,574	-	120,574	23,000	97,574
0118200	Central Records	19,866	21,176	(1,310)	10,538	9,328
LEGAL:		542,209	364,257	177,952	382,121	160,088
0119200	Controller Miscellaneous	94,859	-	94,859	29,178	65,681
CONTROLLER MISCELLANEOUS:		94,859	-	94,859	29,178	65,681

ATMOS ENERGY CORPORATION

Analysis of Shared Services - Actual vs. Budget

For The Month Ended 4/30/99

Department Name	FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
ATMOS OVERHEAD CAPITALIZED:					
0119800 Overhead Capitalized	(900,000)	(884,920)	(15,080)	(881,000)	(19,000)
ATMOS OVERHEAD CAPITALIZED:	(900,000)	(884,920)	(15,080)	(881,000)	(19,000)
MERGER & INTEGRATION:					
0119220 Merger & Integration	495,700	345,255	150,445	-	495,700
MERGER & INTEGRATION:	495,700	345,255	150,445	-	495,700
TOTAL O&M	4,586,362	4,531,311	55,051	2,211,864	2,374,498
DEPRECIATION	808,645	639,000	169,645	270,919	537,726
TAXES - OTHER	98,385	72,500	25,885	69,777	28,608
TOTAL	5,493,392	5,242,811	250,581	2,552,560	2,940,832

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Year-To-Date 4/30/99

Department Name		FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
EXECUTIVE:						
0050500	Chairman, President & CEO	1,657,183	991,877	665,306	936,883	720,300
0050600	Business Process Initiative	946,696	-	946,696	-	946,696
0052100	Dallas Operations	323,969	249,837	74,132	309,173	14,796
0052500	Utility Services	33,718	-	33,718	120,127	(86,409)
0054700	Chief Financial Officer	709,734	844,799	(135,065)	535,376	174,358
EXECUTIVE:		3,671,300	2,086,513	1,584,787	1,901,559	1,769,741
FINANCE:						
0112900	VP & Controller	466,771	-	466,771	565,924	(99,153)
0113000	Director, Utility Accounting	131,539	114,420	17,119	81,704	49,835
0113100	General Accounting	377,761	358,888	18,873	251,210	126,551
0113200	Payroll Accounting	373,481	388,594	(15,113)	263,968	109,513
0113300	Accounts Payable	301,731	270,374	31,357	150,991	150,740
0113400	Accounting Systems	7,708	-	7,708	21,562	(13,854)
0113500	Assistant Controller, Utility Acctg	191,646	-	191,646	26,060	165,586
0113600	Plant Accounting	249,336	229,894	19,442	209,126	40,210
0113700	Gas Accounting	755,424	599,791	155,633	376,882	378,542
0113800	Customer Billing	28,362	-	28,362	47,560	(19,198)
0113900	Financial Reporting	412,460	317,735	94,725	151,228	261,232
0114600	Dallas Taxation	531,272	324,335	206,937	129,564	401,708
0118300	Dallas Stores	(2,675)	-	(2,675)	191	(2,866)
ACCOUNTING		3,824,816	2,604,031	1,220,785	2,275,970	1,548,846
0115000	Information Services	172,895	189,363	(16,468)	175,580	(2,685)
0115100	Production Services	1,414,297	1,510,039	(95,742)	1,011,663	402,634
0115300	Information Systems	592,941	643,538	(50,597)	1,651,373	(1,058,432)
0115400	Information Support	640,499	572,042	68,457	705,701	(65,202)
0115500	Office Equipment	70,830	29,750	41,080	259,486	(188,656)
0115600	Telecommunication Services	181,897	182,392	(495)	20,720	161,177
INFORMATION TECHNOLOGY		3,073,359	3,127,124	(53,765)	3,824,523	(751,164)
0116400	Internal Audit	322,619	407,274	(84,655)	-	322,619
INTERNAL AUDIT		322,619	407,274	(84,655)	-	322,619
0054900	Investor Relations	633,743	890,360	(256,617)	-	633,743
0052400	Public Affairs	3,334	-	3,334	729,360	(726,026)
0117700	Corporate Communications	237,479	404,358	(166,879)	131,930	105,549
INVESTOR RELATIONS		874,557	1,294,718	(420,161)	861,290	13,267

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Year-To-Date 4/30/99

	Department Name	FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
0054200	Retail Services	-	-	-	-	-
0054600	New Business Ventures	138,372	-	138,372	5,236	133,136
NEW BUSINESS VENTURES		138,372	-	138,372	5,236	133,136
0054400	Financial & Strategic Planning	396,617	479,909	(83,292)	-	396,617
0054500	Business Strategics & Competitive Intelligence	361	-	361	313,425	(313,064)
0114300	Budget & Planning	21,783	-	21,783	11	21,772
PLANNING & BUDGETING		418,762	479,909	(61,147)	313,436	105,326
0054000	Price Policy & Administration	548,643	1,191,761	(643,118)	-	548,643
PRICE POLICY & ADMINISTRATION		548,643	1,191,761	(643,118)	-	548,643
0054100	Regulatory Affairs	198,352	446,767	(248,415)	-	198,352
REGULATORY AFFAIRS		198,352	446,767	(248,415)	-	198,352
0114500	Dallas Treasury	353,492	402,006	(48,514)	-	353,492
0114700	Dallas Risk Management	913,041	1,912,626	(999,585)	198,643	714,398
0114800	Dallas Treasurer	170,907	171,731	(824)	1,103,956	(933,049)
0115200	Mass Mail	1,442,480	-	1,442,480	123,386	1,319,094
0117600	Purchasing	132,796	145,447	(12,651)	105,328	27,468
0118000	Remittance Processing	1,970,978	4,974,312	(3,003,334)	504,037	1,466,941
0118500	Mail & Supply	134,757	135,590	(833)	134,715	42
0118600	Purchasing & Stores	76,560	81,565	(5,005)	78,166	(1,606)
0118909	Fleet Administration	162	65,421	(65,259)	39	123
TREASURY:		5,195,173	7,888,698	(2,693,525)	2,248,270	2,946,903
TOTAL FINANCE:		14,594,652	17,440,282	(2,845,630)	9,528,725	5,065,927
OPERATIONS:						
0056000	Business Development	94,722	-	94,722	330,394	(235,672)
BUSINESS DEVELOPMENT		94,722	-	94,722	330,394	(235,672)
0120100	Amarillo Call Center	3,865,425	4,646,922	(781,497)	35,417	3,830,008
CALL CENTER		3,865,425	4,646,922	(781,497)	35,417	3,830,008
0051500	Interstate Gas Supply	409,044	417,815	(8,771)	398,533	10,511
0051600	Intrastate Gas Supply	234,939	299,365	(64,426)	320,832	(85,893)
0051700	Corporate Gas Control	284,189	320,625	(36,436)	299,415	(15,226)
0051900	Gas Supply	178,423	186,055	(7,632)	167,660	10,763

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MOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Year-To-Date 4/30/99

Department Name		FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
GAS SUPPLY & GAS CONTROL		1,106,595	1,223,860	(117,265)	1,186,440	(79,845)
0056200	Technical Services	114,301	89,260	25,041	249,111	(134,810)
TECHNICAL SERVICES		114,301	89,260	25,041	249,111	(134,810)
TOTAL OPERATIONS:		5,181,044	5,960,042	(778,998)	1,801,362	3,379,682
HUMAN RESOURCES:						
0056100	Professional Development	133,518	166,624	(33,106)	28,482	105,036
0116900	Executive Compensation	247,694	367,361	(119,667)	-	247,694
0117000	Dallas EAPC	14,006	-	14,006	-	14,006
0117100	Corporate Services	408	-	408	18,923	(18,515)
0117200	Compensation & Employment	178,737	282,834	(104,097)	322,319	(143,582)
0117300	Human Resources - VP	182,535	203,714	(21,179)	141,024	41,511
0117400	Employee & Labor Relations	49,270	74,591	(25,321)	67,186	(17,916)
0117500	Employee Benefits	633,835	526,217	107,618	880,391	(246,556)
0117800	Employee Communications	115,977	214,694	(98,717)	111,750	4,227
0117900	Facilities	105,442	98,640	6,802	94,319	11,123
0118100	Employee Development	203,478	554,415	(350,937)	187,814	15,664
0119000	Employee Relocation Expense	626,451	475,433	151,018	112,795	513,656
0119210	Management Incentive/Variable Pay	889,598	1,341,662	(452,064)	816,667	72,931
0119400	Treasury - Worker's Comp	(1,630)	-	(1,630)	215	(1,845)
0119500	Human Resources - Benefits	112,909	-	112,909	111,330	1,579
0119600	Retirement Costs	1,993,903	2,755,081	(761,178)	1,235,990	757,913
HUMAN RESOURCES:		5,486,131	7,061,266	(1,575,135)	4,129,205	1,356,926
LEGAL:						
0052000	Legal	1,583,200	1,319,770	263,430	2,794,523	(1,211,323)
0052050	General Liability Accrual	3,789,491	-	3,789,491	-	3,789,491
0051400	Contract Administration	85,038	90,158	(5,120)	33,108	51,930
0052200	Governmental Affairs	69,096	227,410	(158,314)	55,830	13,266
0057900	Corporate Secretary	622,149	779,515	(157,366)	630,806	(8,657)
0119300	Outside Directors Retirement Cost	454,395	-	454,395	161,000	293,395
0118200	Central Records	100,972	155,027	(54,055)	89,166	11,806
LEGAL:		6,704,341	2,571,880	4,132,461	3,764,433	2,939,908
0119200	Controller Miscellaneous	(302,413)	-	(302,413)	(1,248)	(301,165)
CONTROLLER MISCELLANEOUS:		(302,413)	-	(302,413)	(1,248)	(301,165)

ATMOS ENERGY CORPORATION
Analysis of Shared Services - Actual vs. Budget
For The Year-To-Date 4/30/99

Department Name	FY '99 Actual	Budget	Actual Over (Under) Budget	Prior Year	Actual Over (Under) Prior
ATMOS OVERHEAD CAPITALIZED:					
0119800 Overhead Capitalized	(6,300,000)	(6,194,440)	(105,560)	(6,167,000)	(133,000)
ATMOS OVERHEAD CAPITALIZED:	(6,300,000)	(6,194,440)	(105,560)	(6,167,000)	(133,000)
MERGER & INTEGRATION:					
0119220 Merger & Integration	3,469,774	2,416,765	1,053,009	-	3,469,774
MERGER & INTEGRATION:	3,469,774	2,416,765	1,053,009	-	3,469,774
TOTAL O&M	32,504,828	31,342,308	1,162,520	14,957,036	17,547,792
DEPRECIATION	5,590,515	4,473,000	1,117,515	1,897,035	3,693,480
TAXES - OTHER	904,493	507,500	396,993	586,900	317,593
TOTAL	38,999,836	36,322,808	2,677,028	17,440,971	21,558,864

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Management Approval

Utility President	Utility President	Utility President	Utility President	Utility President
Non-utility General Manager				

Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN A-1: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• Financial Reporting (AC-01)	• Filing date of required reports • Penalties for noncompliance	• 99% of reports filed timely • No significant penalties for noncompliance
• Payroll Services (AC-02)	• Employee pay date • Payroll taxes paid • Prepare and distribute W-2 forms	• Pay employees timely • No tax penalties • W-2 form filed timely

Business unit obligations
- Respond to requests for data within 48 hours
- Provide time reports and pay changes timely

Terms for default
- Significant penalty for late report
- Significant penalty for inaccurate report
- Payroll 2 days late
- W-2's 10 days late
- Significant penalties for late tax payments

Capacity requirements
(see attached)

Pricing terms

Pricing level (by product)
- $ ________
- Units ________

See attached

	FY99 Contract Price per Customer
AC01	$ .51
AC02	.52
AC03	1.36
AC04	.93
AC05	1.45
AC06	.52
	$5.29
or	$ .44 per month

Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN A-2: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• Utility Accounting Services (AC-03)	• Invoice payment dates • Depreciation studies completed • Business unit financial statements and regulatory reports completed • Discounts for prompt payment lost	• 90% of A/P invoices paid within two days • WIP report prepared within 5 days of monthly close • Financial statements provided within 5 days of monthly close
• Gas Accounting Services (AC-04)	• Large Volume billing • Revenue reporting • Revenue related tax payments • Gas cost recovery	• LV billing complete by 16th • 99% of revenue taxes paid timely • Pay gas purchase invoices • Respond to data requests within 48 hours

Business unit obligations
- Invoices to Dallas within 2 days of terms
- WIPS unitization and approvals for new assets within one month
- Engineering information entered within one month
- Enter material issue and return tickets within 2 days
- Provide customer usage timely
- Execute customer contracts timely

Terms for default
- Less than 90% A/P invoices paid within 2 days
- Financial reports not provided within 5 days
- Failure to file regulatory reports per schedule
- Large Volume billing 2 days late
- Significant penalties for late payment of taxes

Capacity requirements
(see attached)

Pricing terms

Pricing level (by product)
- $ ________
- Units ________

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Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN A-3: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• Financial Systems & Business Controls (AC-05)	• Financial transactions processed timely • Timely detection and correction of computer application processing errors • Computer sub-ledgers balanced and reconciled on a timely basis • 99% financial computer application processing integrity rate • Financial computer application system projects completed on time with less than 25% cost overrun • 90% of customer surveys indicate a satisfactory service level	• 95% financial application systems availability • 99% accuracy in application processing and data integrity • Financial systems implementation completed on time and within budget • Satisfactory performance in consulting services

Business unit obligations
- Request assistance for performance measurement
- Provide information timely
- Communicate feedback on a constant basis

Terms for default
- More than 5% downtime
- More than 1% error processing rate
- Greater than 25% cost overrun

Capacity requirements
(see attached)

Pricing terms

Pricing level (by product)
- $ ________
- Units ________

7/10/98 11:23

Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN A-4: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• Tax Services (AC-06)	• Tax returns filed • Taxes paid	• 99% of all returns filed on time • Penalties less than 1% of taxes

Business unit obligations
- Provide 90% of information needed within 48 hours

Terms for default
- Less than 99% of returns not filed on time
- Penalties greater than 1% of taxes

Capacity requirements
(see attached)

Pricing terms

Pricing level (by product)
- $________
- Units ________

Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

[illegible]	Energas		[illegible]		[illegible]		UCG		WKG		Propane	
	Total ($K)	No. of Units	Total ($K)	No. of Units	Total ($K)	No. of Units	Total ($K)	No. of Units	Total ($K)	No. of Units	Total ($K)	No. of Units
Fin Reporting AC-01 states	100	2	124	2.5	40	0.8	174	3.5	50	1	12	0.25
Payroll Svcs AC-02 empl	119	406	58	199	40	138	204	698	79	271		
Utility Acctg AC-03 invoices (000'	346 -	42	292	35.5	107	13	309	37.5	247	30		
Gas Acctg AC-04 % hrs	225	25	171	19	108	12	288	32	108	12		
A/S & Bus Cont AC-05 Cust (000's)	439	315	270	194	113	78	333	239	245	176		
Tax Services AC-06 states	93	2	104	2.25	37	0.8	208	4.5	46	1	12	0.25
Total	$ 1,322		$ 1,019		$ 445		$ 1,516		$ 775		$ 24	

Shared Services
Department name: Accounting Services

Agreement duration (months, years) FY 1999

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expense description

- Objective
  - Capital budget amount included in I.T. Strategic Plan which includes Oracle Financial System (hardware and software) implementation
- Estimated cost: -0-
- Start date:

Completion date:

Business unit allocation

Business unit name	Allocation amount (000's)	Allocation rationale – Number of Customers
Energas		
Greeley Gas		
Trans La		
UCG		
UCG Energy		
WKG		

Management approval

Tom S. Hawkins, Jr.
Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

7/14/98 7:35

Shared Services
Left header
Department name

Credit & Collections

COPY

Right header

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	**Performance metrics (quality, timeliness)**	**Minimum service level required**	**Pricing level (by product)**
RP-1 Remittance Processing	Percent of payments processed timely	95% of payments processed same day received in processing center	$ 0.200 Units: monthly per customer
	Percent of payments processed accurately	99.95% of payments applied to correct account first time	
	Error corrections made within given timeframe	95% of errors corrected within 48 hours	
RP-2 Pay Center	Percent of payments processed timely	98% of payments processed same day received in processing center	$ 0.597 Units: monthly per payment
RP-3 Telepay	Percent of payments processed accurately	99.95% of payments applied to correct account first time	$ 5.25 Units: monthly per payment
RP-4 Bank Draft	Error corrections made within given timeframe	95% of errors corrected within 48 hours	$ 0.072 Units: monthly per payment
RP-5 Credit	Percent of credit applications worked timely	To be determined	$ 0.006 Units: monthly per customer
RP-6 Collections	Rate of recovery on write-offs Percentage of shut-offs avoided	To be determined To be determined	$ 0.017 Units: monthly per customer
RP-7 Mass Mail	Percent of Statements Processed Timely Percent of Statements Processed Accurately		$ 0.430 Units: monthly per statement

Management approval

CEO Utility President

Utility President

CFO

Shadow box

Utility President

Utility President

Shared Services Provider

Utility President

Non-utility General Manager

(1)
Note
Source

G:\Treasurer\Shared Services\Cedit & Collections 1999 Agreement.ppt

Credit & Collections

Right header

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Business unit obligations

- Timely requests for credit information
- Assistance in working past due large volume customers

Capacity requirements (see attached)

Terms for default

- 5% of payments not processed timely as agreed
- 5% of payments not applied correctly as agreed
- 5% of error corrections not made timely as agreed
- 5% of credit applications not worked timely
- Rate of recovery lower than agreed
- Percentage of shut-offs higher than agreed

Pricing terms

Management approval

CEO

Utility President

Utility President

CFO

Shadow box

Utility President

Utility President

John P. Rehby

Shared Services Provider

Thomas K. Black

Utility President

Non-utility General Manager

(1)
Note
Source

Credit & Collections

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description

Capital expense description

- Objective
  - Replacement of office equipment

- Estimated cost: $107.2
- Start date: 10-01-98 Completion date: 09/30/99

Performance metrics ~~(quality, timeliness)~~ Minimum service level required

Product description (continued)

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENG	32.4	Number of customers
GGC	20.9	
TRA	8.6	
UGC	26.4	
WKG	18.9	
UCGE	0	

Terms for default

Management approval

CEO

CFO

Shadow box

Shared Services Provider

John P. Reddy

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

(1) Note:

Source:

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)
RP-1 Rem. Proc.	513.3	2,566	331.9	1,659	135.8	683	419.1	2,091	300.1	1,495	0	0
RP-2 Pay Center	425.6	713	275.1	461	112.6	190	347.4	581	248.8	415	0	0
RP-3 Telepay	0.9		0.6		0.3		0.8		0.5		0	
RP-4 Bank Drafts	20.7	285	13.3	184	5.5	76	16.8	232	12.1	166	0	0
RP-5 Credit	21.0	297	13.6	192	5.5	79	17.1	242	12.2	173	0	0
RP-6 Collections	61.2	297	39.6	192	16.2	79	50.0	242	35.8	173	0	0
RP-7 Mass Mail	1,531.7	3,564	990.4	2,304	405.4	948	1,250.7	2,904	895.5	2,076	0	0
Totals	2,574.4		1,664.5		Shadow box 681.3		2,101.9		1,505.0		0	

(1)
Note:
Source:

Shared Services
Department name Gas Supply
EFFECTIVE 9/1/98

COPY

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level (by product)
GS1 Procurement	• Comparison to an appropriate gas price index	• No more than $.05 above the 12 month index average	• GS1 - $1315.34 per Bcf purchased - $2480.00 per contract managed / year
GS2 Nominations and Scheduling	• Sys. Supply noms processed End-user noms processed	• 100% of Sys Sup and > 98% of end-user noms meeting PL deadlines	• GS2 - $600 per mo. per EBB monitored - $20.50 per nom./change
GS3 Storage	• Storage inventory maintained	• Storage filled 90% by Nov 1 Adequate storage to stay within supplier contract on a late peak	• GS3 - $2661.11 per storage contract managed / yr. - $3258.50 per Bcf storage quantities
GS4 Gas Control	• Pipeline Contract compliance System pressure control	• < 10% overrun unless PL authorized Maintain adequate pressure	• GS4 - $622.53 per SCADA point monitored per year - $2014.93 per pipeline contract managed / yr - $1273.58 per storage contract managed / yr.
GS5 Forecasting	• Pipeline capacity and purchase requirements	• 90% accurate with normalization	• GS5 - $43.58 per hour
GS6 PBR Administration	• Accurate documentation	• Satisfactory internal audit report and state regulatory filings - filed on time with 98% accuracy	• GS6 - $35.52 per hour

Business unit obligations

GS1- Assist in evaluating system requirements from an operational perspective

GS2 - Communicate information to transportation end-users as required by agreed upon deadline

GS3 - Responsible for the curtailment of carriage and interruptible end-users within 6 hours. Additionally provides operational and technical support for company owned storage fields

GS4 - Install, calibrate and maintain field measurement equipment

GS5 - Communicate new load additions and changes in industrial load patterns on a regular basis

GS6 - Provide support for PBR programs at the state commissions as requested

Shared Services
Department name Gas Supply
(EFFECTIVE 9/1/98)

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms	Pricing terms
Terms for Default • GS1 - Business Unit gas commodity cost in excess of $.10 above minimum service level • GS2 - Any cost resulting from failure to properly nominate system supply - Excessive verbal or written complaints from marketers or end-users that are not defendable • GS3 - Failure to have storage 80% filled by Nov 1 without justifiable reasons - Any cost resulting from insufficient storage levels to meet late peak requirements that cannot be reasonably justified • GS4 - 20% unauthorized overrun excluding force majeure conditions • GS5 - 80% or more difference after normalization • GS6 - More than 10 substantial audit deficiencies	

Management approval

				Shared Services Provider
Utility President	Utility President	Utility President	Utility President	Utility President
Non-utility General Manager				

Shared Services
Department name: Gas Supply

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		TransLa		UCG		WKG		
	Total $	Number of units	Total $	Number of units	Total $	Number of units	Total $	Number of units	Total $	Number of units	TOTAL $
GS1 Procurement											
Purchased Quantities [1]	$70,800	53.8	$40,100	30.5	$10,100	7.7	$78,500	59.7	$32,500	24.7	$232,000
Supply Contracts	$86,800	35	$99,200	40	$37,200	15	$62,000	25	$62,000	25	$347,200
											$579,200
GS2 Nominations & Scheduling											
Number of EBBs	$0	0	$43,200	6	$14,400	2	$50,400	7	$14,400	2	$122,400
Number of Noms.	$2,300	112	$23,100	1129	$4,600	224	$58,000	2829	$146,100	7127	$234,100
GS3 Storage											
Storage Contracts	$0	0	$23,900	9	$13,100	5	$79,800	30	$26,600	10	$143,400
Storage Quantities [1]	$0	0	$20,500	6.3	$2,300	0.7	$42,400	13	$30,600	9.4	$95,800
GS4 Gas Control											
SCADA Points	$79,700	128	$74,700	120	$0	0	$210,400	338	$107,700	173	$472,500
Pipeline Contracts	$10,100	5	$28,200	14	$18,100	9	$54,400	27	$24,200	12	$135,000
Storage Contracts	$0	0	$8,900	7	$6,400	5	$40,800	32	$11,500	9	$67,600
GS5 Forecasting											
Hourly	$40,600	932	$24,800	569	$10,400	239	$28,900	663	$22,200	509	$126,900
GS6 PBR Admin.											
Hourly	$4,000	113	$12,000	338	$8,000	225	$65,000	1830	$44,000	1239	$133,000
Total	$294,300		$398,600		$124,600		$770,600		$521,800		$2,109,900
[1] Quantities in Bcf	13.9%		18.9%		5.9%		36.5%		24.7%		

Shared Services
Department name Gas Supply

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expense description

- Objective: Computer equipment upgrades for Gas Supply

- Estimated cost: $11,700
- Start date: 10/01/98

Completion date: 02/28/99

Business unit allocation - All Business Units except Propane

Business unit name	Allocation amount ($)	Allocation rationale
Energas	$3,644	Number of customers
Greeley	2,340	
TransLa	936	
UCG	2,691	
WKG	2,089	

Management approval

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Shared Ser[illegible]
Department name: GOVERNMENTAL AFFAIRS

COPY

FY1999

SHARED SERVICES AGREEMENT

SERVICE LEVEL TERMS

	Product Name	Performance Metrics	Minimum Service level required
GA1	Legislative research, Administration and Issues Coordination	• Percentage timely notice of legislative issues or activities • Accuracy and usefulness of information provided	• 95% of notice or action deadlines met • "Satisfactory" or higher response to written survey
GA2	Lobbying and Political Campaigns	• Effort and achievement of GA department and outside lobbyists • Viability of PAC activities	• "Satisfactory" or higher response to written survey • PAC membership/funding maintained at historical levels or higher • PACs in compliance with regulatory standards • Membership informed in periodic reports on current issues/ candidates

Business Unit Obligations

- Provide timely feedback on legislative proposals furnished by GA
- Notify GA of local initiatives, candidates or issues affecting business unit.
- Maintain required filings and provide operational support for PACs

Terms for Default

- Less than 80% deadlines met
- Less than "satisfactory" response to annual written surveys
- Feedback by business unit not provided in a timely manner
- PAC cited for reporting/record keeping violations by business unit

PRICING TERMS

Pricing Level (by product) $/hr

- Legislative research and issues coordination - $70.36 per hour labor
- Lobbying and political campaigns - $70.36 per hour labor (actual fees and expenses of outside lobbyists extra)

CAPACITY REQUIREMENTS:
See Attached

SHARED SERVICES AGREEMENT

MANAGEMENT APPROVAL				
				Shared Services Provider
Utility President	Utility President	Utility President	Utility President	Utility President
Non-utility General Manager				

TOTAL BUDGET & CAPACITY REQUIREMENTS

PRODUCT	ENERGAS		GREELEY		TRANS LA		UNITED CITIES		WKG		PROPANE	
	Total $	No./hrs.	Total $	No./hrs.	Total $	No./hrs.	Total $	No./hrs.	Total $	No./hrs.	Total $	No./hrs.
GA1	20,413	289	13,331	189	5,485	78	16,802	238	12,011	170	1,389	20
GA2												
1) Labor	20,413	289	13,331	189	5,485	78	16,802	238	12,011	170	1,389	20
2) Outside Lobbyists	70,000		27,000		70,000		27,490 *		55,000		2,510 *	
TOTALS	**110,826**	**578**	**53,662**	**378**	**80,970**	**156**	**61,094**	**476**	**79,022**	**340**	**5,288**	**40**

*Lobby fees allocated between United Cities and Propane on basis of customer ratios.

GOVERNMENTAL AFFAIRS BUDGET

	1998 (Current Year)	1999
Rent	$ -	$ 7,200.00
Supplies	$ 600.00	$ 300.00
Postage	$ 300.00	$ 300.00
Travel	$ 11,938.00	$ 24,000.00
Miscellaneous	$ 2,400.00	$ -
Membership Fees	$ 1,200.00	$ 1,200.00
Seminars	$ 1,704.00	$ 1,704.00
Books	$ 2,400.00	$ 200.00
Permits	$ 200.00	$ 200.00
Corporate Contributions	$ 5,000.00	$ -
Allocations	$ 900.00	$ 900.00
Exempt Labor/Benefits	$ 98,901.00	$102,857.00
Sub-Total	$ 125,543.00	$138,861.00
Lobbyists	$ 243,000.00	$252,000.00 •
TOTAL	**$ 368,543.00**	**$390,861.00**

ALLOCATED TO BUSINESS UNITS	1998	1999
Energas Company	$ 108,542.00	$110,825.00
Greeley Gas Company	$ 41,061.00	$ 53,662.00
Trans Louisiana Gas Company	$ 69,918.00	$ 80,970.00 •
United Cities Gas Company	$ 65,935.00	$ 61,094.00
Western Kentucky Gas Company	$ 76,469.00	$ 79,023.00
Propane	$ 6,618.00	$ 5,287.00
TOTAL	**$ 368,543.00**	**$390,861.00**

• Includes $10,000 retainer for additional lobbyist requested by Business Unit.

Shared Services

Department Name: Corporate Secretary

COPY Agreement duration (months, years) 1999

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
CS1 • Board of Director Assistance	• Accomplishment of Goals	• CS1 and 2: Customer satisfaction survey
CS2 • Monitor Insider Trading Policy	• Accuracy and Response in record retrieval	
CS3 • Storage and Retrieval of Records		• CS3: 90% of the time records are delivered within 24 hours of the promised delivery date.

Business unit obligations
- Provide technical and business information in a timely manner
- Changes to project scope that cause changes in due dates must be approved by proper levels
- Requests must clearly describe scope of service being requested

Terms for default
- Failure to provide records services 50% of the time within 24 hours of the promised delivery date
- Failure to meet customer expectations 50% of the time regarding corporate secretary services
- Failure to provide technical and business information as needed

Capacity requirements (see attached)

Pricing terms

Pricing level (by product)

CS1 $.99
No. of customers

CS2 $.15
No. of customers

CS3 $19.14 per box per year
No. of boxes - 17,496

MANAGEMENT APPROVAL

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Corp Secretary

Shared Services
Department name: Corporate Secretary

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

	Energas		Greeley		TransLa		UCG		WKG		Propane	
Product	Total ($)	Number of Units(Cust)	Total ($)	Number Units(Cust)	Total ($)	Number of Units(Cust)	Total ($)	Number of Units(Cust)	Total ($)	Number of Units(Cust)	Total ($)	Number of Units(Cust)
CS1	298,942	301,962	194,418	196,382	79,771	80,577	245,628	248,109	174,976	176,743	8,418	8,503
CS2	46,050	307,000	29,949	199,660	12,288	81,920	37,837	252,247	26,954	179,693	1,297	8,647
CS3	99,895	5,219	64,967	3,394	26,656	1,393	82,079	4,288	58,470	3,055	2,813	147
TOTAL	444,887	614,181	289,334	399,436	118,715	163,889	365,544	504,644	260,400	359,492	12,528	17,297

H.

Shared Services Department: Corporate Secretary

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expense description

- Objective:
  - 2 Optra E Printers
  - 1 17" Monitor
  - 1 Fireproof Filing Cabinet
- Estimated cost: $2,525.00
- Start date: 10/1/98 Completion date: 10/1/99

Business unit name	Allocation amount($	Allocation rationale
Energas Company	$753.21	Number of Customers
Trans La	$200.99	Number of Customers
WKG	$440.87	Number of Customers
Greeley	$489.85	Number of Customers
United Cities	$618.88	Number of Customers
Propane	$21.20	Number of Customers

Management Approval

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Shared Services
Department name Dallas HR FY 1999

COPY

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	**Performance metrics (quality, timeliness)**	**Minimum service level required**	**Pricing level ($000)/Unit**
Employee Benefits Services	• cost to deliver benefits • pension and benefit payroll checks issued in accordance with published schedule • inquiries responded to within agreed on time frames • benefit related transactions handled within agreed on time frames • satisfaction survey	• value of benefits equal to or slightly better than gas utility industry • inquiries to 3rd party vendors within contractual arrangements • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	Direct: $11.063 Total: $13.215 Actual benefits load, SEBP, and Relocation costs will be allocated to each BU based on current accounting methodologies)
Employment Services	• transactions processed within agreed on time frames • inquires responded to within agreed on time frames • satisfaction survey	• 95% of transactions received by published cutoff date and time will be processed • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.143 • Total $0.178 • Propane $0.00
Compensation Services	• transactions processed within agreed on time frames • inquires responded to within agreed on time frames • satisfaction survey	• 95% of transactions received by published cutoff date and time will be processed • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.549 • Total: $1.496 Actual performance bonus plan expenses incurred by BU will be billed to BU.

Shared Services
Department name Dallas HR

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level ($000)/Unit
Employee Development Services	• accurate employee training records • turnaround time to educational assistance requests • satisfaction survey	• 99% accuracy rate for training records • educational assistance requests processed within 2 business days • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.549 • Total: $0.614 • Propane $0.00
Professional Development	• full utilization of available positions	• 5 vacancies filled by 9/30/98	• Direct: $1.224 • Total: $1.809 • Propane $0.00
Employee & Labor Relations	• availability for consultation • satisfaction survey	• respond to 95% of all requests for consultation within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.071 • Total: $0.088 • Propane $0.00
Employee Communications	• communication products delivered in accordance with agreed on schedule • satisfaction survey	• 98% on time delivery of communications products • 99% of electronic notifications distributed within 1 business day of when notified • 90% of survey results at the satisfactory level or better	• Direct: $0.184 • Total: $0.230 • Propane $0.00

Shared Services
Department name Dallas HR

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
Building Services	• availability to handle projects • satisfaction survey	• respond to 95% of all project requests within 2 business days • 90% of survey results at the satisfactory level or better

Business unit obligations

- 95% attendance at all meetings/conference calls to: establish transaction processing time frames; goals to be accomplished in FY; employee development, technical and safety training, and professional development plans and programs; employee communications product schedule; and building services projects.
- 100% commitment to employee development, technical and safety training and professional development plan when developed within budget constraints and operational demands.
- 95% of all transaction paperwork submitted within established time frames, with appropriate approvals and error free
- Complete satisfaction surveys within 10 business days of when provided.

Terms for default

- less than 95% of transactions submitted on time not processed
- more than 5% of inquiries not responded to within 1 business day
- workers' compensation claims, employment litigation, EEOC charges settled without approval of BU President
- less than 95% of the transaction paperwork submitted by BU is not submitted within established time frames, does not have appropriate approvals or contains other errors

Capacity requirements (see attached)

Pricing terms

Pricing level ($000)/Unit

- Direct: $0.035
- Total: $0.141

Management approval

Wynn McGregor
Shared Services Provider

Utility President

Utility President

Utility President

Thomas Black
Utility President

Utility President

Non-utility General Manager

Shared Services
Department name Dallas HR FY 1999

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level ($000)/Unit
Employee Benefits Services	• cost to deliver benefits • pension and benefit payroll checks issued in accordance with published schedule • inquiries responded to within agreed on time frames • benefit related transactions handled within agreed on time frames • satisfaction survey	• value of benefits equal to or slightly better than gas utility industry • inquiries to 3rd party vendors within contractual arrangements • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	Direct: $11.063 Total: $13.215 Actual benefits load, SEBP, and Relocation costs will be allocated to each BU based on current accounting methodologies)
Employment Services	• transactions processed within agreed on time frames • inquires responded to within agreed on time frames • satisfaction survey	• 95% of transactions received by published cutoff date and time will be processed • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.143 • Total $0.178 • Propane $0.00
Compensation Services	• transactions processed within agreed on time frames • inquires responded to within agreed on time frames • satisfaction survey	• 95% of transactions received by published cutoff date and time will be processed • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.549 • Total: $1.496 Actual performance bonus plan expenses incurred by BU will be billed to BU.

Shared Services
Department name Dallas HR

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	**Performance metrics (quality, timeliness)**	**Minimum service level required**	**Pricing level ($000)/Unit**
Employee Development Services	• accurate employee training records • turnaround time to educational assistance requests • satisfaction survey	• 99% accuracy rate for training records • educational assistance requests processed within 2 business days • respond to 95% of all inquiries within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.549 • Total: $0.614 • Propane $0.00
Professional Development	• full utilization of available positions	• 5 vacancies filled by 9/30/98	• Direct: $1.224 • Total: $1.809 • Propane $0.00
Employee & Labor Relations	• availability for consultation • satisfaction survey	• respond to 95% of all requests for consultation within 1 business day • 90% of survey results at the satisfactory level or better	• Direct: $0.071 • Total: $0.088 • Propane $0.00
Employee Communications	• communication products delivered in accordance with agreed on schedule • satisfaction survey	• 98% on time delivery of communications products • 99% of electronic notifications distributed within 1 business day of when notified • 90% of survey results at the satisfactory level or better	• Direct: $0.184 • Total: $0.230 • Propane $0.00

Shared Services
Department name: Dallas HR

Agreement duration (months, years): 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
Building Services	• availability to handle projects • satisfaction survey	• respond to 95% of all project requests within 2 business days • 90% of survey results at the satisfactory level or better

Business unit obligations

- 95% attendance at all meetings/conference calls to: establish transaction processing time frames; goals to be accomplished in FY; employee development, technical and safety training, and professional development plans and programs; employee communications product schedule; and building services projects.
- 100% commitment to employee development, technical and safety training and professional development plan when developed within budget constraints and operational demands.
- 95% of all transaction paperwork submitted within established time frames, with appropriate approvals and error free
- Complete satisfaction surveys within 10 business days of when provided.

Terms for default

- less than 95% of transactions submitted on time not processed
- more than 5% of inquiries not responded to within 1 business day
- workers' compensation claims, employment litigation, EEOC charges settled without approval of BU President
- less than 95% of the transaction paperwork submitted by BU is not submitted within established time frames, does not have appropriate approvals or contains other errors

Capacity requirements (see attached)

Pricing terms

Pricing level ($000)/Unit

- Direct: $0.035
- Total: $0.141

Management approval

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

DALLAS HUMAN RESOURCES

FY 98 - FY 99 Shared Services Contract Reconciliation

Category	FY 98	FY 99	Difference	Notes
Responsibility Centers				
VPHR	264,633	324,697	60,064	1
Compensation & Employment	727,946	502,999	(224,947)	
Employee and Labor Relations	114,956	129,906	14,950	
Employee Benefits	1,330,161	843,719	(486,442)	2
Employee Development	460,761	517,643	56,882	3
Facilities Coordinator	161,234	168,911	7,677	
Employee Communications	235,980	335,216	99,236	4
Professional Development	296,657	285,648	(11,009)	
Dallas Executive Compensation		619,500	619,500	5
Capital	382,700	81,233	(301,467)	6
	3,975,028	3,809,472	(165,556)	
Benefits Load	20,555,372	16,759,135	(3,796,237)	7
Other:				
SEBP	2,700,000	4,723,000	2,023,000	8
Relocation	815,000	815,000	-	9
Performance Bonus Plan*	1,115,000	2,300,000	1,185,000	10
Senn-Delaney	-	475,000	475,000	
	4,630,000	8,313,000	3,683,000	
TOTAL	29,160,400	28,881,607	(278,793)	
Allocation Amounts				
Energas	6,583,163	7,266,100	682,937	11
GGC	3,614,588	5,550,300	1,935,712	12
TransLa	2,102,288	2,349,400	247,112	13
WKG	4,974,900	4,603,700	(371,200)	14
UCG	9,823,552	7,469,900	(2,353,652)	15
Propane	2,061,884	1,642,200	(419,684)	16
TOTAL	29,160,375	28,881,600	(278,775)	

* 1998 Performance Bonus Plan was budgeted at $1,115,000; however it is estimated that $1,820,100 will be paid out for 1998 based on max earnings @ $1.69

Footnotes

1 Executive comp elements removed
2 Executive comp elements removed, inreased service awards costs
3 Safety and Technical training responsibilities added.
4 Enhanced Communication commitment
5 New responsibility center created/software maintenance added
6 Reduced capital needs/HRIS first year software maintenance
7 Revised FAS 87 expense calculation after UCG integration
8 Relocation services are being reviewed for outsourcing opportunities and to reduce costs
9 Projected target payment for proposed mgmt incentive plan
10 Management Directed
11 Increased allocation because of decreased allocation to propane
12 Includes UCG's KS EE's/increased allocation because of decreased allocation to propane
13 Increased allocation because of decreased allocation to propane
14 Reduced Benefits Load/increased allocation because of decreased allocation to propane/reduced credit on pension plan
15 Excludes UCG's KS EE's/increased allocation because of decreased allocation to propane
16 Revised allocation of costs, there is no allocation of indirect costs in this number

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation						
Product Number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR01	Employee Benefits Services	Benefits Load based on individual BU projections,Responsibility Center SEBP and Relocation based on complement. Propane has been only benn allocated their direct costs.	Energas	20.8%	4,945.3	4,945.3					
			GGC	16.3%	3,872.5		3,872.5				
			TransLa	6.3%	1,503.4			1,503.4			
			WKG	13.1%	3,103.0				3,103.0		
			UCG	21.0%	5,001.3					5,001.3	
			Propane	6.2%	1,476.4						1,476.4
			SSUs	16.3%	3,872.7	1,040.3	737.7	347.5	669.1	1,078.1	-
			Total	100.0%	23,774.5	5,985.6	4,610.1	1,851.0	3,772.1	6,079.4	1,476.4
			Percent of Total		100%	25.2%	19.4%	7.8%	15.9%	25.6%	6.2%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation						
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR02	Employment Services	Based on number of employees	Energas	21.5%	62.8	62.8					
			GGC	15.2%	44.5		44.5				
			TransLa	7.2%	21.0			21.0			
			WKG	13.8%	40.4				40.4		
			UCG	22.3%	65.0					65.0	
			Propane	0.0%	-						-
			SSUs	20.0%	58.5	15.7	11.1	5.2	10.1	16.3	-
			Total	100.0%	292.1	78.5	55.6	26.2	50.5	81.3	-
			Percent of Total		100.0%	26.9%	19.0%	9.0%	17.3%	27.8%	0.0%

10/9/98

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation					
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR03	Compensation Services	Based on number of employees. Mgmt. Incentive Plan based on employee salaries eligible for plan	Energas	9.3%	250.3	250.3					
			GGC	8.4%	225.6		225.6				
			TransLa	5.6%	150.8			150.8			
			WKG	6.0%	162.3				162.3		
			UCG	10.5%	283.6					283.6	
			Propane	6.8%	184.4						184.4
			SSUs	53.3%	1,435.0	385.5	273.3	128.8	247.9	399.5	-
			Total	100.0%	2,692.1	635.8	499.0	279.6	410.2	683.1	184.4
			Percent of Total		100.0%	23.6%	18.5%	10.4%	15.2%	25.4%	6.8%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

								Direct and Indirect Allocation			
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR04	Employee Development	Based on number of employees	Energas	20.5%	206.1	206.1					
			GGC	14.3%	143.2		143.2				
			TransLa	6.9%	69.4			69.4			
			WKG	13.3%	133.2				133.2		
			UCG	25.3%	254.6					254.6	
			Propane	0.0%	-						-
			SSUs	19.7%	198.4	53.3	37.8	17.8	34.3	55.2	-
			Total	100.0%	1,005.0	259.4	181.0	87.2	167.5	309.8	-
			Percent of Total		100.0%	25.8%	18.0%	8.7%	16.7%	30.8%	0.0%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation					
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR05	Professional Development	Based on number of management positions in each BU and all SS providers combined.	Energas	17.1%	55.1	55.1					
			GGC	11.4%	36.7		36.7				
			TransLa	6.8%	22.0			22.0			
			WKG	12.5%	40.4				40.4		
			UCG	19.8%	63.7					63.7	
			Propane	0.0%	-						-
			SSUs	32.3%	104.1	26.3	17.5	10.5	19.3	30.4	-
			Total	100.0%	322.0	81.4	54.3	32.6	59.7	94.1	-
			Percent of Total		100.0%	25.3%	16.9%	10.1%	18.5%	29.2%	0.0%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation						
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR06	Employee & Labor Relations	Based on number of employees	Energas	21.5%	31.0	31.0					
			GGC	15.2%	22.0		22.0				
			TransLa	7.2%	10.4			10.4			
			WKG	13.8%	20.0				20.0		
			UCG	22.3%	32.2					32.2	
			Propane	0.0%	-						-
			SSUs	20.0%	28.9	7.8	5.5	2.6	5.0	8.1	-
			Total	100.0%	144.5	38.8	27.5	13.0	25.0	40.2	-
			Percent of Total		100.0%	26.9%	19.0%	9.0%	17.3%	27.8%	0.0%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

								Direct and Indirect Allocation			
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR07	Employee Communications	Based on number of employees	Energas	21.5%	81.1	81.1					
			GGC	15.2%	57.5		57.5				
			TransLa	7.2%	27.1			27.1			
			WKG	13.8%	52.2				52.2		
			UCG	22.3%	84.0					84.0	
			Propane	0.0%	-						-
			SSUs	20.0%	75.6	20.3	14.4	6.8	13.1	21.0	-
			Total	100.0%	377.4	101.4	71.9	33.9	65.2	105.1	-
			Percent of Total		100.0%	26.9%	19.0%	9.0%	17.3%	27.8%	0.0%

10/9/98

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

						Direct and Indirect Allocation					
Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Energas	GGC	TransLA	WKG	UCG	Propane
HR08	Building Services	75% of services provided to SSUs and corporate center; remaining costs allocated based on square footage of buildings in each BU.	Energas	5.9%	11.3	11.3					
			GGC	2.5%	4.9		4.9				
			TransLa	1.7%	3.3			3.3			
			WKG	3.7%	7.1				7.1		
			UCG	9.9%	19.1					19.1	
			Propane	1.3%	2.5						2.5
			SSUs	75.0%	144.5	35.7	15.4	10.4	22.5	60.4	-
			Total	100.0%	192.7	47.0	20.3	13.7	29.6	79.5	2.5
			Percent of Total		100.0%	24.4%	10.5%	7.1%	15.4%	41.3%	1.3%

Shared Services
Department Name: Dallas HR

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
FY 1999
Customer Allocation ($000)

Product number	Product Name	Allocation Rationale	Customers	Allocation %	Direct Allocation	Direct and Indirect Allocation: Energas	GGC	TransLA	WKG	UCG	Propane
HR09	Capital Expenditures	Based on number of employees	Energas	21.5%	17.5	17.5					
			GGC	15.2%	12.4		12.4				
			TransLa	7.2%	5.8			5.8			
			WKG	13.8%	11.2				11.2		
			UCG	22.3%	18.1					18.1	
			Propane	0.0%	-						-
			SSUs	20.0%	16.3	4.4	3.1	1.5	2.8	4.5	-
			Total	100.0%	81.2	21.8	15.5	7.3	14.0	22.6	-
			Percent of Total		100.0%	26.9%	19.0%	9.0%	17.3%	27.8%	0.0%
			Grand Total		28,881.6	7,249.7	5,535.2	2,344.4	4,593.8	7,495.2	1,663.3
			Percent of Total		100.0%	25.1%	19.2%	8.1%	15.9%	26.0%	5.8%

Shared Services
Department Name: Dallas HR FY 1999

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product		Energas		GGC		TransLa		WKG		UCG		Propane		Total		Description
		Total ($000)	Number of Units	Total ($000)	Number of Units	Total ($000)	Number of Units	Total ($000)	Number of Units	Total ($000)	Number of Units	Total ($000)	Number of Units	Total ($000)	Number of Units Cost/Unit	
HR01	DIRECT	4,945.3		3,872.5		1,503.4		3,103.0		5,001.3		1,476.4		19,901.9	11.063	Direct/Unit
	INDIRECT	1,040.3	440	737.7	312	347.5	147	669.1	283	1,078.1	456	-	161	3,872.7	1,799	Employees
	Sub-Total	5,985.6		4,610.1		1,851.0		3,772.1		6,079.4		1,476.4		23,774.5	13.215	Total/Unit
HR02	DIRECT	62.8		44.5		21.0		40.4		65.0		-		233.6	0.143	Direct/Unit
	INDIRECT	15.7	440	11.1	312	5.2	147	10.1	283	16.3	456	-	-	58.5	1,638	Employees
	Sub-Total	78.5		55.6		26.2		50.5		81.3		-		292.1	0.178	Total/Unit
HR03	DIRECT	256.5		230.0		152.9		166.2		290.0		155.8		1,251.4	0.696	Direct/Unit
	INDIRECT	387.0	440	274.4	312	129.3	147	248.9	283	401.1	456	-	161	1,440.7	1,799	Employees
	Sub-Total	643.5		504.4		282.2		415.1		691.1		155.8		2,692.1	1.496	Total/Unit
HR04	DIRECT	241.5		171.2		80.7		155.3		250.2		-		898.9	0.549	Direct/Unit
	INDIRECT	28.5	440	20.2	312	9.5	147	18.3	283	29.5	456	-	-	106.1	1,638	Employees
	Sub-Total	270.0		191.4		90.2		173.6		279.8		-		1,005.0	0.614	Total/Unit
HR05	DIRECT	55.1		36.7		22.0		40.4		63.7		-		217.9	1.224	Direct/Unit
	INDIRECT	26.3	45	17.5	30	10.5	18	19.3	33	30.4	52	-	-	104.1	178	Mgmt Positions
	Sub-Total	81.4		54.3		32.6		59.7		94.1		-		322.0	1.809	Total/Unit
HR06	DIRECT	31.0		22.0		10.4		20.0		32.2		-		115.6	0.071	Direct/Unit
	INDIRECT	7.8	440	5.5	312	2.6	147	5.0	283	8.1	456	-	-	28.9	1,638	Employees
	Sub-Total	38.8		27.5		13.0		25.0		40.2		-		144.5	0.088	Total/Unit
HR07	DIRECT	81.1		57.5		27.1		52.2		84.0		-		301.9	0.184	Direct/Unit
	INDIRECT	20.3	440	14.4	312	6.8	147	13.1	283	21.0	456	-	-	75.6	1,638	Employees
	Sub-Total	101.4		71.9		33.9		65.2		105.1		-		377.4	0.230	Total/Unit
HR08	DIRECT	11.3		4.9		3.3		7.1		19.1		2.5		48.2	0.035	Direct/Unit
	INDIRECT	33.9	320.0	14.6	138.1	9.9	93.5	21.4	201.6	57.3	541.0	7.5	70.7	144.5	1,365	(000) Sq. Ft
	Sub-Total	45.2		19.5		13.1		28.5		76.4		10.0		192.7	0.141	Total/Unit
HR09	DIRECT	17.5		12.4		5.8		11.2		18.1		-		65.0	0.040	Direct/Unit
	INDIRECT	4.4	440	3.1	312	1.5	147	2.8	283	4.5	456	-	-	16.3	1,638	Employees
	Sub-Total	21.8		15.5		7.3		14.0		22.6		-		81.2	0.050	Total/Unit
	TOTAL	7,266.1		5,550.3		2,349.4		4,603.7		7,469.9		1,642.2		28,881.6		

Grand Total 28,881.6

10/9/98

Shared Services IR/CC - 1999
Department name

COPY

Agreement duration (months, years) 12 Months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• IRCC1 External Communications	• Financial Reports • Bill Inserts	• 0 Missed Deadlines • 0 Missed Deadlines, 0 Errors
• IRCC2 Shareholder Communications	• Shareholder/Investor Communications Response Time • Investor Communications - Response time accuracy/ meetings	• 0 Incidence SEC Non-compliance • 2 Day Response Material Requests • 24 Hr. Response to Phone Calls

Business unit obligations

- Financial Reporting - Supply Information for Business Unit
- Bill Inserts - Supply Information for Business Unit
- Feedback - Discuss Concerns

Terms for default

- Deadlines missed
- Incidence SEC Non-Compliance
- More than incidences day response

Capacity requirements (see attached)

Pricing terms

Pricing level (by product)

- $694,555
- $ Units 1.214(B)

Pricing level (by product)

- $1.53 mm
- $ Units 1.214(B)

Total Product 1 & 2

- $2.22 mm
- $ Units 1.214(B)

Management approval

Lynn Nord
Shared Services Provider

Utility President

Utility President

Earl Fischer
Utility President

Utility President

Utility President

Eugene A. Ellen
Non-utility General Manager

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Shared Services
Department name IRCC1 & IRCC2

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expense description
- Objective

- Estimated cost: $15,900
- Start date: 10/1/98

Completion date: 9/30/99

Business unit allocation

Business unit name		Allocation amount ($)	Allocation rationale
ENG	20.46	$3253	Gross Plant Investment (Modified)
GGG	11.00	1749	
TRA	9.24	1469	
UCG	41.05	6527	
WKG	15.35	2441	
UGE	2.9	461	

Management approval

Utility President

Utility President

Utility President

Utility President

Shared Services Provider

Utility President

Non-utility General Manager

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Shared Services
Department name IR/CC - 1999

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)
IRCC1	$142.1	239540	$76.4	128851	$64.2	107969	$285.1	480458	$106.6	179590	$20.1	78072
IRCC2	$312.8	"	$168.1	"	$141.2	"	$627.5	"	$234.6	"	$44.4	"
TOTAL	$454.9	"	$244.5	"	$205.4	"	$912.8	"	$341.3	"	$64.5	"

Shared Services
Department name Internal Audit

COPY

Agreement duration (months, years) 12 mo.

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level (by product)
IA01 Financial Audit	Quarterly audits completed for E&Y to correspond to press release deadlines	2,000 hours of audit assistance Satisfactory rating by E&Y	$54 per hour
IA02 Operational Audit	Accurate findings reported with high quality recommendations	Customer satisfaction rating of 4 or above	$57 per hour
IA03 Compliance Audit	Report delivered within one week after fieldwork	Customer satisfaction rating of 4 or above	$86 per hour
IA04 Special Investigation	Investigation complete within one month of request	Response time met for at least two projects per year, as requested	$71 per hour

Business unit obligations

Complete schedule requests or gathering of information by beginning of fieldwork (two week notice for products 1-3)
Commit assistance of one person for same hours as auditors during fieldwork (product 4)
Maintain availability of appropriate personnel during fieldwork to answer questions and provide responses to recommendations

Terms for default

Intervention by Audit Committee of Board of Directors or Acquisition due diligence requiring more than 500 hours or ratings of 2 or below on satisfaction surveys

Capacity requirements (see attached)

Management approval

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Shared Services Department name Internal Audit

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (Hrs)	Total ($K)	Number of units (Hrs)	Total ($K)	Number of units (Hrs)	Total ($K)	Number of units (Hrs)	Total ($K)	Number of units (Hrs)	Total ($K)	Number of units (Hrs)
IA01 Financial	$33	605	$21	391	$ 9	160	$27	494	$19	354	$ -	-
IA02 Operation	64	1,116	41	722	17	296	52	911	37	653	-	-
IA03 Compliance	86	999	56	646	23	265	70	816	50	584	12	200
IA04 Investigation	26	371	17	240	7	98	21	303	16	217	-	-
Total	209		135		56		170		122		12	

Shared Services

Department: Legal 1999

COPY

Agreement duration: 12 months

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
LE 1 Research/Training/Advice LE 2 Research/Training/Advice: Indirect LE 3 Contract Drafting, Negotiation, Review LE 4 Contract Drafting: Indirect LE 5 Litigation Management LE 6 Contract Administration	- Timeliness of Response - Customer Satisfaction Survey - Monthly Status Reports	- 90% of the time the product will be delivered within 24 hours of the promised delivery date. - LE 5: 80% of the time, outcomes achieved will be reasonable based upon circumstances of the case (measured by survey)

Business unit obligations

Project requests must clearly describe full scope of service being requested
Allow Legal Department to manage use of outside counsel
Provide technical and business information to Legal Dept. in a timely manner
Changes to project scope that cause changes in due dates must be approved By proper levels

Terms for default

Failure to provide legal work 50% of the time within 24 hours of promised Delivery date
Failure to provide contract admin. services 50% of the time within 24 hours of Promised delivery date
Failure to meet customer expectations 50% of the time regarding litigation Management
Use of outside counsel by Business Unit without prior authorization of the Legal Dept.
Failure of the Business Unit to provide technical and business information as needed

Monthly amounts to be billed directly to Business Unit:

Trans La
Settlements: $27,000
$50,000 (10/98 – 12/98 only)
Retainer Fees: $4,167

Energas
Settlements: $6,666.67 (10/98 – 1/99 only)

Pricing terms

Pricing level (by product)

		Hours
LE 1	$67.88	3,500
LE 2	$82.00	5,900
LE 3	$70.17	3,600
LE 4	$81.73	6,200
LE 5	$93.87	2,500
LE 6	$36.25	4,300

NOTE: Settlement amounts, Retainer fees, etc., will be billed Directly to the responsible Business Unit.

MANAGEMENT APPROVAL

CEO

CFO

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

ared Services

partment name: Legal 1999

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($)	Number of Units (hrs.)	Total ($)	Number of Units (hrs.)	Total ($)	Number of Units (hrs.)	Total ($)	Number of Units (hrs.)	Total ($)	Number of Units (hrs.)	Total ($)	Number of Units (hrs.)
	70,918	1,045	47,278	697	16,536	244	59,062	870	42,527	627	1,259	19
	144,418	1,761	96,279	1,174	33,673	411	120,276	1,467	86,602	1,056	2,564	31
	75,401	1,075	50,267	716	17,581	251	62,796	895	45,215	644	1,339	19
	151,258	1,851	100,839	1,234	35,268	432	125,973	1,541	90,704	1,110	2,686	33
	70,052	746	46,701	498	16,334	174	58,341	622	42,008	448	1,244	13
	46,529	1,284	31,019	856	10,849	299	38,751	1,069	27,902	770	826	23
TOTALS	558,576	7,762	372,383	5,175	130,241	1,811	465,199	6,464	334,958	4,655	9,918	138

Shared Services

Department name: LEGAL 1999

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expense description

- Objective: See Attached
  -
  -
  -
- Estimated cost: $25,055.00
- Start date: 10/1/98

Completion date: 10/1/99

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
Energas Company	$7,489	Number of customers
Trans La	$1,746	Number of customers
WKG	$4,490	Number of customers
Greeley	$4,991	Number of customers
United Cities	$6,236	Number of customers
Propane	$ 103	Number of customers

Management approval

CEO

CFO

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

LEGAL DEPARTMENT 1999 CAPITAL BUDGET

Four replacement PC's, Three 17" monitors	$ 12,355
One scanner/sheet feeder	$ 2,500
One OCR Software	$ 800
One laptop computer	$ 3,800
One software for laptop	$ 600
Two file cabinets	$ 1,000
One color printer	$ 4,000
TOTAL	**$ 25,055**

Shared Services
Department name Planning & Budgeting

COPY

Agreement duration (months, years): 10 98 09 99

SHARED SERVICES AGREEMENT - A

Service level terms

Product name

- PB01 - Business plan development, consolidated reporting and analytical services
- PB02 - Ad-hoc financial & economic analysis services
- PB03 - Capitalization analysis services
- PB04 - Corporate development analysis and reporting
- PB05 - Industry analysis
- PB06 - Capital spending support and reporting
- PB07 - Operation & maintenance expense support & reporting
- PB08 - Budget System Application Development
- PB02a 06a, & 07a - SSU Support

Performance metrics (quality, timeliness)

- Direct support will be measured with quality/responsiveness surveys to the actual BU. Indirect support will be measured with surveys to the SSU and/or management committee that is supported.
- System support will be measured by monitoring response time for system support questions/problems.

Minimum service level required

- Meet or exceed BU or SSU expectations 80% of the time based on customer survey.
- System support (PB06 and PB07) will resolve 90% of non-technical problems within one business day. Technical problems will be addressed within one business day.

Terms for default

- Customer satisfaction/ responsiveness surveys do not meet or exceed expectations more than 50% of the time.
- BU does not meet deadlines for providing information in conjunction with Five Year Plans, detail annual budgets, etc. on a consistent basis.
- Non-technical system support does not resolve problems within one business day 50% of the time. Technical problems are not addressed within one day 50% of the time.

Capacity requirements (see attached)

Business unit obligations

- Coordinate use of Planning & Budgeting resources with other business units
- Commit sufficient resources to Planning & Budgeting activities at the BU level to meet deadlines for providing information in conjunction with Five Year Plans, detail annual budgets, etc.
- Maintain capital budget system authority table records for BU personnel
- Provide resources/input for modifications and/or evaluations of new Planning & Budgeting Technology.

Pricing terms

Pricing level (by product)

Product #	Hours (Units)	Cost/ Hour
PB01	3120	$62
PB01a	1560	$62
PB02	1560	$60
PB03	520	$63
PB04	2080	$61
PB05	520	$54
PB06	1560	$49
PB06a	520	$50
PB07	520	$48
PB07a	520	$47
PB08	2080	$51
Total	7 FTE	

Management approval

Tom E. Hulus Jr.
Shared Services Provider

Utility President | Utility President | Utility President | Utility President | Utility President

Eugene H. Ehle

Non-utility General Manager

Shared Services
Department name: Planning & Budgeting

SSU AGREEMENT B - CAPITAL EXPENSE ADDENDUM

Capital expense terms

Capital expenditure description:

- Upgrade department computers.
- Objective - maintain hardware in department that allows maximum use of technology.
- Estimated cost: $5,000
- Start date: 10/98 Completion date: 09/99

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENG	$1,206	Total number of customers
GGC	840	Total number of customers
TLA	423	Total number of customers
UCG	1,755	Total number of customers
WKG	673	Total number of customers
UCGE	103	Total number of customers

Management approval

Shared Services Provider

Utility President Utility President Utility President Utility President Utility President

Non-utility General Manager

TEMPLATE SEVEN A - ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Shared Services

Department name Planning and Budgeting

Product	Energas		Greeley		Trans LA	
	Total $	Number of Hours	Total $	Number of Hours	Total $	Number of Hours
PB01	$48,100	753	$34,700	524	$15,400	264
PB01a	26,000	377	18,300	262	8,700	132
PB02	19,700	377	14,100	262	9,400	132
PB03	6,600	126	3,900	87	2,900	44
P304	36,900	502	26,600	349	8,900	176
PB05	8,100	126	5,900	87	2,000	44
PB06	16,200	377	11,600	262	7,700	132
PB06a	5,600	126	3,900	87	2,600	44
PB07	4,300	126	3,400	87	2,100	44
PB07a	5,400	126	3,100	87	1,900	44
PB08	23,200	502	13,800	349	8,500	176
PB09	0	0	0	0	0	0
	$200,100	3,515	$139,300	2,446	$70,100	1,232
Total %	25%		17%		8%	

TEMPLATE SEVEN A - ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS
Shared Services
Department name Planning and Budgeting

Product	United Cities		Western Kentucky		United Cities Energy		Total	
	Total $	Number of Hours	Total $	Number of Hours	Total $	Number of Hours	Total $	Number of Hours
PB01	$63,600	1,095	$15,400	420	$15,400	64	$192,600	3,120
PB01a	34,700	547	8,700	210	0	32	96,400	1,560
PB02	36,700	547	14,100	210	0	32	94,000	1,560
PB03	12,700	182	4,900	70	1,600	11	32,600	520
PB04	31,700	730	22,800	280	0	43	126,900	2,080
PB05	7,100	182	5,100	70	0	11	28,200	520
PB06	30,100	547	11,600	210	0	32	77,200	1,560
PB06a	10,200	182	3,900	70	0	11	26,200	520
PB07	10,700	182	4,200	70	0	11	24,700	520
PB07a	9,900	182	3,900	70	0	11	24,200	520
PB08	43,500	730	17,000	280	0	43	106,000	2,080
PB09	0	0	0	0	0	0	0	0
	$290,900	5,109	$111,600	1,960	$17,000	298	$829,000	14,560
Total %	35%		13%		2%		100%	

Shared Ser...

Department name Price Policy & Administration ("PP&A")

COPY

Agreement duration (months, years) 1 year

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT (FY '99)

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
• Gas Cost Adjustments (GCA) • Actual Cost Adjustments (ACA) • Base Rate Changes filings • Custom filings /ad hoc projects • Strategic Planning Expertise • Regulatory Relations maintenance	• Percent on time filings • Percent PP&A workmanship error • Percent of favorable outcomes re: price change applications • Percent of favorable outcomes re: merger filings, ad hoc projects, etc.	• 95% regulatory deadlines met • 60% of all proceedings outcomes favorable • 90% GCA's approved as filed • 90% PP&A workmanship accuracy

Special terms: PP&A will provide B.U. specific resource deployment reports for each billing period stated on an approximate FTE hourly basis contemporaneous with billing reports.

Business unit obligations
- Keep L&U below regulatory allowable maximum
- Minimize metering/reporting error or delay
- Collaborate on regulatory liaison
- Maximize Customer satisfaction/complaint minimization
- Maintain sterling safety compliance and incident avoidance/minimization

Terms for default
- Less than 80% of filing deadlines met
- Less than 30% of proceedings outcomes favorable
- Less than 75% of GCA's approved as filed

Capacity requirements (see Template Five)

Pricing terms

Products priced by FTE commitment. Template Five incorporated by reference.

Monthly Chg. w/o Rate Cases

Energas	$16,668
Greeley	$25,000
TransLa	$11,064
UCG	$70,200
WKG	$14,023

Monthly Chg. w/ Rate Cases

Energas	$19,226
Greeley	$25,917
TransLa	$11,064
UCG	$98,153
WKG	$18,606

Management approval

CEO

CFO

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Shared Services
Department name Price Policy & Administration

TEMPLATE FIVE: COST ALLOCATION TEMPLATE
Customer Allocation

Customers	Resource Commitment (FTE)	Total Costs To Be Billed	Average Hourly Rate	Monthly Charge	Deferred Rate Case	Total with Rate Case	Monthly Total with Rate Case
Energas	1.80	200,016	53.60	16,668	30,700	230,716	19,226
Greeley	2.69	300,000	53.60	25,000	11,000	311,000	25,917
TransLa	1.20	132,768	53.60	11,064	-	132,768	11,064
United Cities	7.55	842,400	53.60	70,200	335,437	1,177,837	98,153
WKG	1.51	168,276	53.60	14,023	55,000	223,276	18,606
Total	14.75	1,643,460	53.60	136,955	432,137	2,075,597	172,966

Shared Services Department name: Purchasing

COPY

Agreement duration (months, years) 1 YR

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Product name	Performance metrics (quality, timeliness)	Minimum service level required
P-1 • Procurement Services	• Percent of P.O.'s issued on time • Price of material within budget • Percent of orders delivered on time	• 95% of P.O.'s issued within 5 workdays after receipt of requisition • 90% of material within budget • On-line order status updated weekly
P-2 • Fleet Administration	• Time required to respond to budget request and AFE's • Percent of budgeted vehicles ordered prior to factory cutoff date	• 2-day response to budget requests and AFE's • 98% of budgeted vehicles ordered prior to buildout date
P-3 • Mail and Supply	• Percent of supplies delivered on time	• 95% of office supplies delivered within 24 hours

Business unit obligations
- Provide complete and approved requisitions on a timely basis
- Provide technical answers to questions within 2 days
- Receipt for materials within 2 days after received
- Provide budgeted price

Terms for default
- Less than 95% of P.O.'s issued in 5 workdays
- Price of material over budget greater than 10%
- Less than 75% of materials delivered on time

Capacity requirements (see attached)

Pricing terms

Pricing level (by product)
- $ ______
- Units ______

P-1 $33.03 per P.O.

P-2 $76.13 per vehicle

P-3 $149.03 per employee

Management approval

John P. Reddy
Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

Eugene A. [illegible]

Shared Services
Department name **Purchasing**

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)
P-1	82.6	2.5	56.2	1.7	39.6	1.2	99.1	3.0	72.7	2.2		
P-2	31.9	0.4	15.2	0.2	9.7	0.1	45.7	0.6	20.1	0.3		
P-3	65.4	0.4	30.8	0.2	21.9	0.1	83.6	0.6	42.2	0.3		
TOTAL	179.9		102.2		71.2		228.4		135.0			

Shared Services Department name **Purchasing**

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM (I)

Capital expense terms

Capital expense description Labor allocated to store expense
- **Objective**

- **Estimated cost:** **$227,329**
  Start date: October 1, 1998

Completion date: **September 30, 1999**

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENERGAS	$53,616	Number of purchase orders
TRANSLA	$25,735	
WKG	$47,182	
GGC	$36,458	
UCG	$64,338	
UCGE		

Management approval

John P. Reddy
Shared Services Provider

Utility President | Utility President | Utility President | Utility President | Utility President

Non-utility General Manager

Eugene H. Ehler

Shared Services
Department name **Purchasing**

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM (II)

Capital expense terms

Capital expense description New P.C. for Purchasing
- **Objective**

- **Estimated cost:** $2,800
  Start date: October 1, 1998

Completion date: September 30, 1999

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENERGAS	$660	Number of purchase orders
TRANSLA	$317	
WKG	$581	
GGC	$449	
UCG	$793	
UCGE		

Management approval

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

MEMORANDUM

ATMOS

TO: Tom Blose
Gene Ehler
Earl Fischer
B. J. Hackler
Gary Schlessman

FROM: J. R. Jones

DATE: June 1, 1998

Costs associated with Purchasing's shared services for FY'99 were affected by the following:

1. Product P-1 (Procurement Services) up $7,200

    a. Overall costs were reduced; however the necessity to budget for software maintenance more than negated that reduction.

    b. Costs allocated to the Propane unit in FY'98 were re-allocated to the regulated Business Units for FY'99

2. Product P-2 (Fleet Administration) up $44,800

    a. Fleet Administrator's position was under-budgeted in FY'98 and the Fleet Assistant was a new position in the FY'99 budget

    b. Costs allocated to the Propane unit in FY'98 were re-allocated to the regulated Business Units for FY'99

3. Product P-3 (Mail & Supply) Flat Budget

    a. Costs allocated to the Propane Unit in FY'98 were re-allocated to the regulated Business Units for FY'99

Should you need additional information, please call me.

P. O. Box 650205 Dallas, Texas 75265-0205 972-934-9227

Rec 7-7-98.

Shared Services
Left header
Department name

Risk Management

COPY

Right header

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level (by product)
RM-1 Insurance Procurement	• Timely insurance placement of appropriate limits	100% of policies renewed on time No gaps in coverage	$ 2.45 Units: annual per thousand dollar revenue
RM-2 Claims Management	• Investigate all claims and direct to a conclusion	95% favorable customer feedback	$ .095 Units: annual per thousand dollar revenue
RM-3 Litigation Support	• Assist in defense of litigation and insurance recovery	95% favorable customer feedback	$ .042 Units: annual per thousand dollar revenue
RM-4 Loss Control	• Coordinate safety audits and standards	95% favorable customer feedback	$ ..036 Units: annual per thousand dollar revenue

Management approval

John P. Reddy
Shared Services Provider

Utility President | Utility President | Utility President | Utility President | Utility President

Eugene H. Ehlen

(1) Non-utility General Manager
Note
Source

Risk Management

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms	Pricing terms

Business unit obligations

- Prompt reporting of claims
- Assist in field investigations
- Maintain service records
- Provide input for local claims climate
- Enforce O&M manual

Terms for default

- Lapse in coverage
- Claims issues not addressed
- Insurance support not provided
- Failure to qualify for coverage

Capacity requirements (see attached)

Management approval

John S. Reddy
Shared Services Provider

Utility President | Utility President | Utility President | Utility President | Utility President

Non-utility General Manager

(1)
Note:
Source:

Risk Management

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)
RM 1 Ins/ Procurement	809.8	253	524.4	236	161.2	112	992.5	404	456.4	192	131.3	58
RM 2 Claims Mgmt.	31.4	253	20.3	236	6.2	112	38.4	404	17.7	192	5.1	58
RM 3 Litigation Support	13.8	253	8.9	236	2.7	112	17.0	404	7.8	192	2.2	58
RM 4 Loss Control	12.0	253	7.8	236	2.4	112	14.7	404	6.7	192	1.9	58
Totals	867.0		561.4		172.5		1,062.6		488.6		140.5	

Shadow box

(1)
Note:
Source:

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description

Capital expense description
- Objective
  - Replacement of office equipment

- Estimated cost: $ 5.0
- Start date: 10-01-98

Product description (continued)

Performance metrics ~~(quality, timeliness)~~

Minimum service level required

Completion date: 09/30/99

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENG	1.5	Number of customers
GGC	1.0	
TRA	0.4	
UGC	1.2	
WKG	0.8	
UCGE	0.1	

Terms for default

Management approval

CEO

CFO

Calvin S. Reddy
Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

(1
Note
Source

Treasury

COPY

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level (by product)
TR-1, Short-term debt	• Availability & interest rates on funds borrowed	Funds available 100% of time Interest rates below prime 99% of borrowings	$ 0.140 Units: annual per customer
TR-2, Long-term debt	• Availability & interest rates on funds borrowed	Funds available 100% of time	$ 0.122 per $1K Units: gross PP&E
TR-3, Equity	• Amount of funds raised & dividends reinvested	Funds available when needed	$ 0.037 Units: annual per customer
TR-4, Cash Management	• Timeliness of payments processed	Payments processed by due date 99.9% of time	$ 0.567 Units: annual per customer

Management approval

John P. Reddy
Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

(1)
Note:
Source:

Treasury

Agreement duration (months, years) 09/99

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Business unit obligations

- Notification of maximum amount of short-term funds required for following year
- Processing of accounts payable invoices by due date

Terms for default

- Required notification of funds required not submitted by business unit(s)
- Required amount of short-term funds not available by treasury
- Interest rates on short-term funds above prime rate 5% of time
- Required amount of long-term funds not available
- Interest rates on long-term funds above market 5% of time
- Equity funds not available when needed
- 5% of accounts payable invoices not submitted on time by business unit(s)
- 5% of payments not processed on due date

Capacity requirements (see attached)

Pricing terms

Management approval

John P. Reddy
Shared Services Provider

Utility President

Utility President

Paul Fincher
Utility President

Utility President

Thomas R. Blair
Utility President

Eugene A. Euler

Non-utility General Manager

(1)
Notes:
Source:

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product	Energas		Greeley		Trans La		UCG		WKG		Propane	
	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)	Total ($K)	Number of units (K)
TR-1 Short-term debt	42	297	27.5	192	11.6	79	34.7	242	24.6	173	4.3	29
TR-2 Long-term debt	30.5	253,010	29.0	236,281	13.7	112,248	48.9	404,128	22.9	191,924	7.6	58,181
TR-3 Equity	11.0	297	7.2	192	3.0	79	9.1	242	6.5	173	1.1	29
TR-4 Cash Mgmt	173.2	297	112.0	192	45.9	79	141.4	242	101.2	173		
Totals	256.7		175.7		74.1		234.1		155.2		13.0	

Shadow box

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Note:
Source:

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description
Capital expense description

- Objective
  - Replacement of office equipment
  - Treasury Software
- Estimated cost: $25.0
- Start date: 10-01-98 Completion date: 09/30/99

Performance metrics ~~(quality, timeliness)~~ Minimum service level required

Product description (continued)

Business unit allocation

Business unit name	Allocation amount ($)	Allocation rationale
ENG	7.2	Number of customers
GGC	4.8	
TRA	2.0	
UGC	6.0	
WKG	4.2	
UCGE	0.8	

Terms for default

Management approval

Utility President
Utility President
Utility President
John P. Reddy
Shared Services Provider
Utility President
Utility President
Non-utility General Manager
Eugene H. Ehler

(1)
Notes:
Source:

From: Ro[illegible] Ker

COPY

Atmos Energy Corporation Information Technology Shared Services Contract For Fiscal Year 1999

June 22, 1998

Shadow box

(1)
Note:
Source:

Information Technology Shared Services Contract Fiscal Year 1999 Table of Contents

(1)
Note:
Source:

Information Technology Shared Services Contract Fiscal Year 1999 Assumptions

- Assumes and includes O&M cost increases resulting from the implementation of the I.T. Strategy
- Assumes implementation of the I.T. Strategy will begin by July 1, 1998 and no Year 2000 work will be required on GEAC systems (additional $250,000 will be required if Financial, HR and Payroll systems are not updated as part of the I.T. Strategy by September, 1999)
- All of the I.T. Strategy capital costs are in product IT11. These amounts are still under negotiation.
- Application software maintenance will be a part of the contract for the Shared Services units owning the application.
- Assumes inhouse labor for all areas except contractors in Information Systems Support.

Shadow box

(1)
Note:
Source:

Information Technology
Shared Services Contract
Fiscal Year 1999
Major Changes to Budget and/or Contract

- FY1998's IT2 - Mass Mail has been moved to Treasury (FY1998's budget - $4,509,193)
- FY1998's IT7 - Information Systems Support has been changed to IT2
- Propane has been eliminated as a customer (FY1998's billing - $107,861)
- Includes full impact of UCG (decrease of $2.3 million), CSI (increase of $.9 million) and other changes (increase of $.2 million). This is detailed on the next slide.
- Pricing terms for IT1 have been changed from mainframe transactions and number of customers to number of customers only due to reduction in mainframe usage
- Performance measurements for IT2 - Information Systems Support have been changed to reflect the change in focus from developing to maintaining systems
- Maintaining phone directories has been moved to the Call Center

Shadow box

(1)
Note:
Source:

Information Technology
Shared Services Contract
Fiscal Year 1999
Comparison of FY98 O&M to FY99 O&M
(excluding UCG Data Center & Mass Mail)

To O&M

	Net Increases/ (Decreases)	Increases/(Decreases) Resulting From			
		CSI/CIS	UCG Consolidation	Other	Explanation of Other Net
Salaries & Payroll Cost	$453,000	$762,000 7 - CIS Team 1 - Oracle DBA 4 - HelpDesk	$135,000 1 - LAN Admin 2 - IT Control Admin 1 - Admin Asst.	($444,000)	Capital labor for IT Strategy implementation and six months additional capitalization of CSI
Contractors	$374,000			$374,000	Provide mainframe support during the implementation of the IT Strategy
Training	$153,000			$153,000	Additional training required to keep staff current
Other Balance Sheet Accounts	$126,000			$126,000	Quit allocating costs to the Inventory clearing account
Employment Fees	$81,000			$81,000	Projected employment fees
Emergency Data Center	$74,000	$74,000			
UCG Allocation	$60,000			$60,000	Portion of I.T. Management was charged to UCG
Phone Usage	$20,000			$20,000	Phone usage has increased
Mass Mail Allocation	$17,000			$17,000	Half of Computer Operations Supervisor was charged to Mass Mail
Microfiche	($48,000)	($48,000)			
Equipment Maintenance	($163,000)	$7,000		($170,000)	Move equipment maintenance costs to the BU's budgets
Software Maintenance	($117,000)	$113,000		($230,000)	Move application software costs to user's budgets
Other Miscellaneous Changes	$40,000			$40,000	
	~~$1,070,000~~ 1,484,000	$908,000	$135,000	$27,000	

Information Technology
Shared Services Contract
Fiscal Year 1999
Comparison of FY98 O&M to FY99 O&M
(excluding UCG Data Center & Mass Mail)

	Net Increases/ (Decreases)	Increases/(Decreases) Resulting From			
		CSI/CIS	UCG Consolidation	Other	Explanation of Other
Salaries & Payroll Cost	$656,000	$762,000	$135,000	($241,000)	Capital labor for IT Strategy implementation
Contractors	$374,000			$374,000	Provide mainframe support during the implementation of the IT Strategy
Training	$153,000			$153,000	Additional training required to keep staff current
Other Balance Sheet Accounts	$126,000			$126,000	Quit allocating costs to the Inventory clearing account
Employment Fees	$81,000			$81,000	Projected employment fees
Emergency Data Center	$74,000	$74,000			
Phone Usage	$20,000			$20,000	Phone usage has increased
Microfiche	($48,000)	($48,000)			
Equipment Maintenance	($95,000)	$7,000		($102,000)	Move equipment maintenance costs to the BU's budgets
Software Maintenance	($117,000)	$113,000 Shadow box		($230,000)	Move application software costs to user's budgets
	$1,224,000	$908,000	$135,000	$181,000	

(1)
Note:
Source:

TEMPLATE ONE: SHARED SERVICES PRODUCT AND CUSTOMER DEFINITIONS (I)

Product number(1)	Product name	Product description	Customers
IT1	Enterprise Servers Support	Enterprise Server Support (Mainframe, Unix & NT) Enterprise Technical & LAN Planning and Support Data Center Operations System Security, Change Control, Disaster Recovery Data Base Administration	All Utility BU's
IT2	Information Systems Support	Application Support IT Master Planning for Computer Applications Support Assist with New Development and RFP's System Modifications and Enhancements	All Utility BU's
IT3	PC Support	Support of PC and Office Equipment Hardware & Software Installs Upgrades Problem Resolution	All Utility BU's
IT4	Help Desk Support	First and Second Level Support for All I.T. Products	All Utility BU's
IT5	Telecommunications Support	Provide and Support Telecommunications Systems Hardware & Software Installs Upgrades Problem Resolution	All Utility BU's

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(1)
Note:
Source:
(1) Numbering scheme—code—xx with codes provided on backup materials and xx being 01-10

TEMPLATE ONE: SHARED SERVICES PRODUCT AND CUSTOMER DEFINITIONS (II)

Product number(1)	Product name	Product description	Customers
IT6	Enterprise Servers Support (Capital)	Capital Budget Items - in I.T. Strategy for FY99	All Utility BU's
IT7	Information Systems Support (Capital)	Capital Budget Items - in I.T. Strategy for FY99	All Utility BU's
IT8	PC Support (Capital)	Capital Budget Items - PC Utilities and Tools	All Utility BU's
IT9	Help Desk Support (Capital)	Capital Budget Items - in I.T. Strategy for FY99	All Utility BU's
IT10	Telecommunications Support (Capital)	Capital Budget Items - in I.T. Strategy for FY99	All Utility BU's
IT11	I.T. Strategy	Upgrade/Replace Various Systems	All Utiliity BU's

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(1)
Note:
Source:
(1) Numbering scheme—code—xx with codes provided on backup materials and xx being 01-10

TEMPLATE TWO: BUDGET
Department Costs

	Costs			
Number of people (3)	Labor	Benefits	Overhead Allocations (1)	Other (2)
56	$2,771,849	$457,364	$1,727,806	$549,250

Total Budget
$5,506,269

Capital Budget	
Enterprise Server Support	$52,150
Information Systems	$0
PC Support	$10,000
Help Desk Support	$0
Telecommunications	$12,800
I.T. Strategy	$13,680,000
Total	$13,754,950

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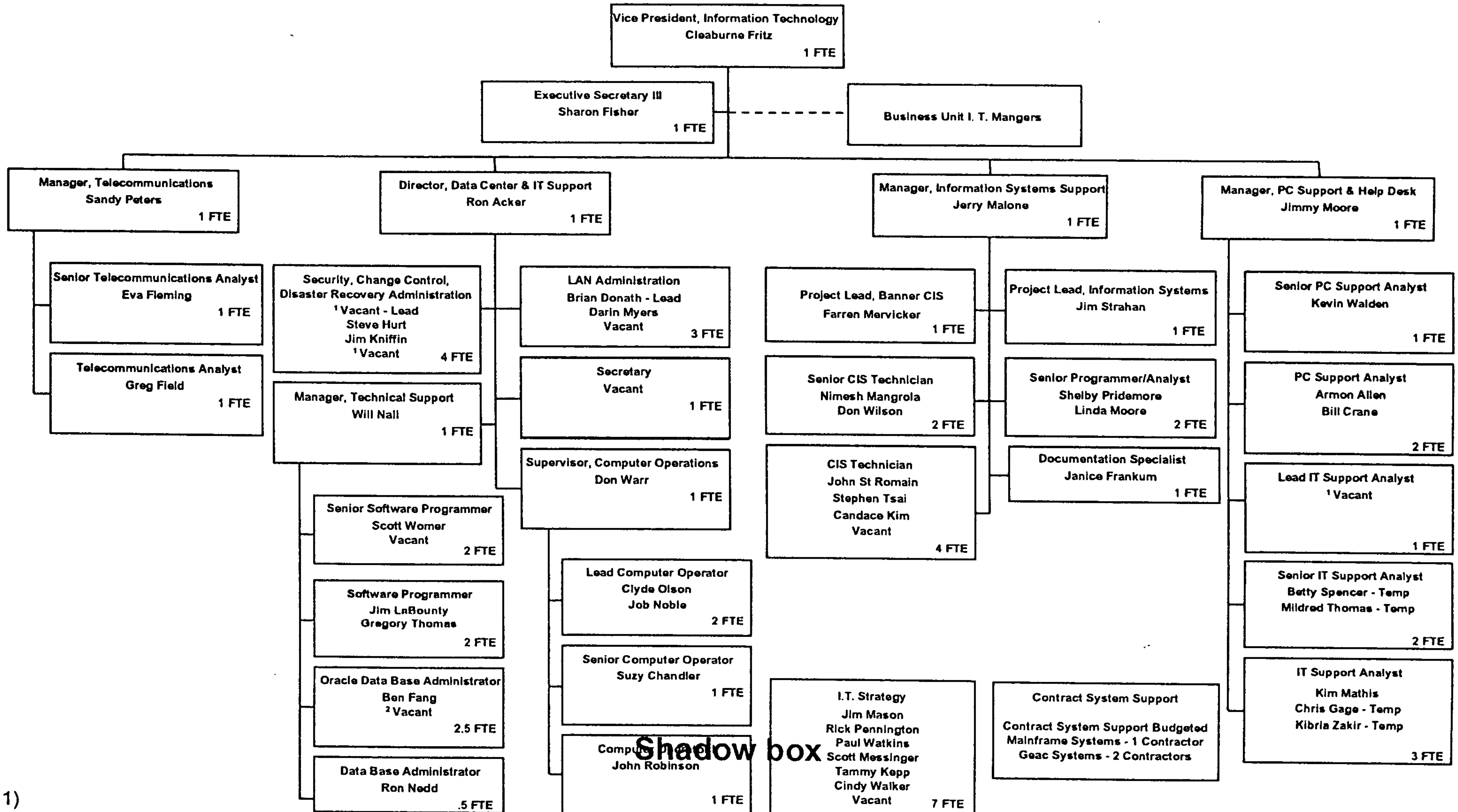
(1)
Note:
Source:

(1) Includes Building Lease, Phone Usage, Software Lease/Maintenance, Hardware Maintenance, and Data Center Supplies/Paper
(2) Includes Contract Labor
(3) Net Addition of 1 Complement (Oracle DBA) Due to CSI Requirements

TEMPLATE THREE: ORGANIZATIONAL CHARTS



(1)
Note:
Source:

[1] These 3 positions are additions due to restructuring of responsibilities. They are offset by 3 reductions in complement (2 IT Support Analysts and 1 Computer Operator I).
[2] This is an addition to complement due to CSI.

TEMPLATE FOUR: COST ALLOCATION (I)

Product Allocation

Product Number	Product Name	Labor (FTE's)	Other Cost Allocation	Other Cost Allocation Rationale	Labor Cost	Other Cost	Total Costs Allocated
IT1	Enterprise Servers Support	22.7	49.67%	O&M Budget plus 35% of I.T. Management's O&M Budget	$1,573,372	$1,131,118	$2,704,490
IT2	Information Systems Support	19.7	32.27%	O&M Budget plus 35% of I.T. Management's O&M Budget	$888,136	$734,784	$1,622,920
IT3	PC Support	3.7	8.14%	O&M Budget plus 10% of I.T. Management's O&M Budget	$242,443	$185,326	$427,769
IT4	Help Desk Support	6.7	4.09%	O&M Budget plus 10% of I.T. Management's O&M Budget	$312,755	$93,194	$405,949
IT5	Telecommunications Support	3.2	5.83%	O&M Budget plus 10% of I.T. Management's O&M Budget	$212,507	$132,634	$345,141
		56.0	100.00%		$3,229,213	$2,277,066	$5,506,269

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(1)
Note:
Source:

TEMPLATE FOUR: COST ALLOCATION (II)
Product Allocation

Product Number	Product Name	Labor (FTE's)	Other Cost Allocation	Other Cost Allocation Rationale	Labor Cost	Other Cost	Total Costs Allocated
IT6	Enterprise Servers Support (Capital)	0.0	0.38%	Cost of the capital expenditures	$0	$52,150	$52,150
IT7	Information Systems Support (Capital) (1)	0.0	0.00%	Cost of the capital expenditures	$0	$0	$0
IT8	PC Support (Capital)	0.0	0.07%	Cost of the capital expenditures	$0	$10,000	$10,000
IT9	Help Desk Support (Capital) (1)	0.0	0.00%	Cost of the capital expenditures	$0	$0	$0
IT10	Telecommunications (Capital)	0.0	0.09%	Cost of the capital expenditures	$0	$12,800	$12,800
IT11	I.T. Strategy (Capital)	0.0	99.46%	Cost of the capital expenditures	$0	$13,680,000	$13,680,000
		0.0	100.00%		$0	$13,754,950	$13,754,950

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(1)
Note:
Source:
(1) Capital for this area is in the I.T. Strategy.

TEMPLATE FIVE: COST ALLOCATION TEMPLATE (I)
Customer Allocation

Product Number	Product Name	Customers	Allocation	Allocation Rationale	Total Costs Allocated
IT1	Enterprise Servers Support	Energas	30.19%	Based on allocation of costs to the	$816,382
		GGC	19.52%	main areas of support which were	$528,030
		TransLa	8.00%	then allocated to the Business Units	$216,237
		UCG	24.65%	based on number of customers. (1)	$666,534
		WKG	17.64%		$477,307
IT2	Information Systems Support	Energas	30.19%	Based on number of customers	$489,960
		GGC	19.52%		$316,794
		TransLa	8.00%		$129,834
		UCG	24.65%		$400,050
		WKG	17.64%		$286,282
IT3	PC Support	Energas	26.55%	Direct allocation based on number of	$113,564
		GGC	15.88%	PC's and indirect allocation based on	$67,932
		TransLa	8.65%	number of customers	$37,002
		UCG	30.33%		$129,728
		WKG	18.59%		$79,543

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(1)
Note:
Source:
(1) In FY1998 IT1 was based on mainframe usage and number of customers. FY1999 is by number of customers only.

TEMPLATE FIVE: COST ALLOCATION TEMPLATE (II)

Customer Allocation

Product Number	Product Name	Customers	Allocation	Allocation Rationale	Total Costs Allocated
IT4	Help Desk Support	Energas	27.51%	Direct allocation based on number of	$111,657
		GGC	19.20%	employees and indirect allocation	$77,954
		TransLa	8.78%	based on number of customers	$35,637
		UCG	27.15%		$110,222
		WKG	17.36%		$70,479
IT5	Telecommunications Support	Energas	27.51%	Direct allocation based on number of	$94,932
		GGC	19.20%	employees, indirect allocation based	$66,277
		TransLa	8.78%	on number of customers	$30,299
		UCG	27.15%		$93,712
		WKG	17.36%		$59,921
IT1-IT5	All Products Combined	Energas	29.54%	Based on allocation of individual	$1,626,495
		GGC	19.20%	products	$1,056,987
		TransLa	8.15%		$449,009
		UCG	25.43%		$1,400,246
		WKG	17.68%		$973,532
					$5,506,269

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(1)
Note:
Source:

TEMPLATE FIVE: COST ALLOCATION TEMPLATE (III)

Customer Allocation

Product Number	Product Name	Customers	Fiscal Year 1998 Allocation	Fiscal Year 1998 Costs	Fiscal Year 1999 Allocation	Fiscal Year 1999 Costs	Increase/ (Decrease)	Percent Change
IT1-IT5	All Products (FY98 figures are exclusive of Mass Mail)	Energas	24.31%	$1,614,709	29.54%	$1,626,495	$11,786	1%
		GGC	9.11%	$605,358	19.20%	$1,056,987	$451,629	75%
		TransLa	6.51%	$432,713	8.15%	$449,009	$16,296	4%
		UCG	44.67%	$2,967,344	25.43%	$1,400,246	($1,567,098)	-53%
		WKG	13.78%	$914,662	17.68%	$973,532	$58,870	6%
		Propane	1.62%	$107,861	N.A.	$0	($107,861)	-100%
			100.00%	$6,642,647	100.00%	$5,506,269	($1,136,378)	-17%

Product Number	Product Name	Customers	Fiscal Year 1998 Allocation	Fiscal Year 1998 Costs	Fiscal Year 1999 Allocation	Fiscal Year 1999 Costs	Increase/ (Decrease)	Percent Change
IT1-IT5	All Products (FY98 figures are exclusive of Mass Mail and UCG Data Center)	Energas	24.31%	$1,628,584	29.54%	$1,626,495	($2,089)	0%
		GGC	9.11%	$610,400	19.20%	$1,056,987	$446,587	73%
		TransLa	6.51%	$436,277	8.15%	$449,009	$12,732	3%
		UCG	44.67%	$624,997	25.43%	$1,400,246	$775,249	124%
		WKG	13.78%	$922,409	17.68%	$973,532	$51,123	6%
		Propane	1.62%	$34,422	N.A.	$0	($34,422)	-100%
			100.00%	$4,257,089	100.00%	$5,506,269	$1,249,180	29%

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See page 5 for a break down of the changes from FY98 to FY99.

(1)
Note:
Source:
(1) IT1 was based on mainframe usgae and number of customers. FY1999 is by number of customers only.

TEMPLATE FIVE: COST ALLOCATION TEMPLATE (IV)
Customer Allocation

Product Number	Product Name	Customers	Allocation	Allocation Rationale	Total Costs Allocated
IT6	Enterprise Servers Support (Capital)	Energas	30.19%	Based on number of customers	$15,744
		GGC	19.52%		$10,180
		TransLa	8.00%		$4,172
		UCG	24.65%		$12,855
		WKG	17.64%		$9,199
					$52,150
IT7	Information Systems Support (Capital)	Energas	30.19%	Based on number of customers	$0
		GGC	19.52%		$0
		TransLa	8.00%		$0
		UCG	24.65%		$0
		WKG	17.64%		$0
					$0
IT8	PC Support (Capital)	Energas	30.19%	Based on number of customers	$3,019
		GGC	19.52%		$1,952
		TransLa	8.00%		$800
		UCG	24.65%		$2,465
		WKG	17.64%		$1,764
					$10,000
IT9	Help Desk Support (Capital)	Energas	30.19%	Based on number of customers	$0
		GGC	19.52%		$0
		TransLa	8.00%		$0
		UCG	24.65%		$0
		WKG	17.64%		$0
					$0

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(1)
Note:
Source:

TEMPLATE FIVE: COST ALLOCATION TEMPLATE (V)

Customer Allocation

Product Number	Product Name	Customers	Allocation	Allocation Rationale	Total Costs Allocated
IT10	Telecommunications Support (Capital)	Energas	30.19%	Based on number of customers	$3,864
		GGC	19.52%		$2,499
		TransLa	8.00%		$1,023
		UCG	24.65%		$3,155
		WKG	17.65%		$2,259
					$12,800
IT11	I.T. Strategy (Capital)	Energas	30.19%	Based on number of customers	$4,129,470
		GGC	19.52%		$2,670,907
		TransLa	8.00%		$1,093,780
		UCG	24.65%		$3,371,501
		WKG	17.65%		$2,414,342
					$13,680,000
IT6-IT10	All Products Combined (Capital)	Energas	30.19%	Based on allocation of individual products	$4,152,097
		GGC	19.52%		$2,685,538
		TransLa	8.00%		$1,099,775
		UCG	24.65%		$3,389,976
		WKG	17.64%		$2,427,564
					$13,754,950

Shadow box

(1)
Note:
Source:

TEMPLATE SIX: QUALITY AND OUTPUT MEASURES DEFINITION

Product number	Product name	Output measures	Quality measures
IT1	Enterprise Servers Support	Number of online transactions on the mainframe Number of megabytes of data downloaded from the Internet Number of Emails sent and received Number of Level Three problems resolved	Percent uptime of the mainframe Percent uptime of the remote access server Percent of problems resolved within agreed upon time Percent of "satisfactory" or above problem resolution surveys
IT2	Information Systems Support	Number of hours Number of incidents resolved Number of projects completed	Percent of problems/requests resolved within agreed upon time Percent of "satisfactory" or above problem/request completion surveys
IT3	PC Support	Number of devices installed Number of Level Three problems resolved Number of requests processed	Percent of problems/requests resolved within agreed upon time Percent of "satisfactory" or above problem/request completion surveys
IT4	Help Desk Support	Number of calls taken Number of problems resolved	Percent of calls answered within agreed upon time Percent of calls resolved by Level One and Level Two Percent of "satisfactory" or above problem resolution surveys
IT5	Telecommunications Support	Number of Level Three problems resolved Number of requests processed	Percent of problems/requests resolved within agreed upon time Percent of "satisfactory" or above problem/request completion surveys Percent availability of the frame relay network

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(1)
Note:
Source:

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms			Pricing terms
Product name	Performance metrics (quality, timeliness)	Minimum service level required	Pricing level (by product)
• IT1 Enterprise Servers Support	• Availability of enterprise servers and network • Mainframe response time • "Satisfactory" response on survey	• 99% availability for the mainframe and CIS server during prime usage time • 97.5% availability for the NT servers and data network during prime usage time • 95% of service surveys indicate "satisfactory" service	• IT1 • $2.75 per customer per year
• IT2 Information Systems Support	• Turnaround time of requests • Resolution time for problems • Projects completed on time and on budget • "Satisfactory" responses to surveys	• 90% of requests and problems completed within agreed upon time • 95% of service surveys indicate "satisfactory" service	• IT2 • $1.65 per customer per year
• IT3 PC Support	• Turnaround time of requests • Resolution time for problems • "Satisfactory" responses to surveys	• 90% of requests and problems completed within agreed upon time • 95% of service surveys indicate "satisfactory" service	• IT3 • $353.53 per PC per year • $.18 per customer per year for indirect charges
• IT4 Help Desk Support	• Call answer time • Percent of calls resolved • "Satisfactory" responses to surveys	• 85% of calls answered within 2 minutes • 60% of all calls to the Help Desk will be resolved by Level One or Level Two, the remainder will be resolved by Level Three • 95% of service surveys indicate "satisfactory" service	• IT4 • $197.35 per employee per year • $.08 per customer per year for indirect charges
• IT5 Telecommunications Support	• Turnaround time of requests • Resolution time for problems • "Satisfactory" responses to surveys	• 90% of requests and problems completed within agreed upon time • 95% of service surveys indicate "satisfactory" service	• IT5 • $167.79 per employee per year • $.07 per customer per year for indirect charges

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(continued)

(1)
Note:
Source:

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Shared Services
Left header
Department name Information Technology

Right header

Agreement duration (months, years) 1 Year

TEMPLATE SEVEN A: SHARED SERVICES AGREEMENT

Service level terms

Business unit obligations
- Project requests are submitted via an IT Request Eform and with enough advance notice to allow for proper planning
- Project requests have a clear and concise definition of what service is being requested
- Changes to project scope that cause changes in due dates and/or costs are approved by proper levels
- Services surveys returned promptly and consistently
- Follow established I.T. Standards

Terms for default
- IT1
  - More than 5% downtime for enterprise servers and network during prime usage time
  - Less than 90% of service surveys indicate "satisfactory" service
- IT2
  - Less than 85% of requests and problems completed on time
  - Less than 90% of service surveys indicate "satisfactory" service
- IT3
  - Less than 85% of requests and problems completed on time
  - Less than 90% of service surveys indicate "satisfactory" service
- IT4
  - Less than 80% of calls answered within 2 minutes
  - Less than 55 % of all Help Desk calls solved by Level One or Level Two
  - Less than 90% of service surveys indicate "satisfactory" service
- IT5
  - Less than 85% of requests and problems completed on time
  - Less than 90% of service surveys indicate "satisfactory" service
- Business Units
  - Requests for which the business unit obligations are not met will not be eligible for the service level agreement

- The budgets contained in this Contract are incorporated by reference into performance metrics. RET

Capacity requirements (see attached)

Pricing terms

Management approval

CEO

Utility President

Utility President

CFO

Shadow box

Utility President

Utility President

Shared Services Provider

Utility President

Non-utility General Manager

(1)
Note
Source

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TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description

Capital expense description - IT6 Enterprise Servers Support

- Objective
  - 3 Laptops, 3 Technical Workstations, 2 Phones, 8 Chairs and a Web-based Openview Client
- Estimated cost: $52,150
- Start date: 10/1/98

Completion date: 3/1/99

Product description (continued)

Business unit allocation

Performance metrics (quality, timeliness)

Minimum service level required

Energas	$15,744	Based on number of customers
GGC	$10,180	
TransLa	$4,172	
UCG	$12,855	
WKG	$9,199	

Terms for default

Management approval

CEO

CFO

Shadow box

Shared Services Provider

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

(1)
Notes:
Source:

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description
Capital expense description - IT8 PC Support
- Objective
  - PC Utilities and Tools
- Estimated cost: $5,000
- Start date: 10/1/98

Product description (continued)

Completion date: 3/1/99

Performance metrics (quality, timeliness)
Business unit allocation

Minimum service level required

Energas	$3,019	Based on number of customers
GGC	$1,952	
TransLa	$800	
UCG	$2,465	
WKG	$1,764	

Terms for default

Management approval

CEO

CFO

Shadow box

Utility President

Utility President

Utility President

Utility President

Shared Services Provider

Utility President

Non-utility General Manager

(1)
Note:
Source:

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TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description
Capital expense description - IT10 Telecommunications
- Objective
  - Phone, Laptop, Upgrade Terranova Software and Modems

- Estimated cost: $12,800
- Start date: 10/1/98

Product description (continued)

Completion date: 3/1/99

Business unit allocation
Performance metrics (quality, timeliness)

Minimum service level required

Energas	$3,864	Based on number of customers
GGC	$2,499	
TransLa	$1,023	
UCG	$3,155	
WKG	$2,259	

Terms for default

Management approval

CEO
Utility President
Utility President
CFO
Shadow box
Utility President
Utility President
Shared Services Provider
Utility President
Non-utility General Manager

(1)
Note:
Source:

TEMPLATE SEVEN B: CAPITAL EXPENSE ADDENDUM

Capital expense terms

Product description

Capital expense description - IT11 I.T. Strategy

- Objective
  - Upgrade/Replace Various Systems

- Estimated cost: $28,000,000
- Start date: 10/1/98

Product description (continued)

Completion date: 10/1/99

Business unit allocation

Performance metrics (quality, timeliness)

Minimum service level required

Energas	$4,129,470	Based on number of customers
GGC	$2,670,907	
TransLa	$1,093,780	
UCG	$3,371,501	
WKG	$2,414,342	

Terms for default

Management approval

CEO

CFO

Shared Services Provider

Shadow box

Utility President

Utility President

Utility President

Utility President

Utility President

Non-utility General Manager

(1)
Note:
Source:

TEMPLATE SEVEN A ATTACHMENT: TOTAL BUDGET AND CAPACITY REQUIREMENTS

Product Name / Units of Measurement	Price Per Unit Per Year	Energas		Greeley		Trans La		UCG		WKG		Total By Product	
		Total Charges	Number of Units Consumed	Total Charges	Number of Units Consumed	Total Charges	Number of Units Consumed	Total Charges	Number of Units Consumed	Total Charges	Number of Units Consumed	Total Charges	Number of Units Consumed
IT1 - Enterprise Server Support													
Customers	$2.75	$816,382	296,604	$528,029	191,841	$216,237	78,562	$666,534	242,162	$477,307	173,413	$2,704,489	982,582
IT2 - Information Systems Support													
Customers	$1.65	$489,898	296,604	$316,862	191,841	$129,760	78,562	$399,976	242,162	$286,424	173,413	$1,622,920	982,582
IT3 - PC Support													
Number of PC's	$353.53	$59,393	168	$32,878	93	$22,626	64	$85,554	242	$48,080	136	$248,531	703
Indirect (Customers)	$0.18	$54,104	296,604	$34,994	191,841	$14,331	78,562	$44,173	242,162	$31,633	173,413	$179,235	982,582
IT4 - Help Desk													
Number of Employees	$197.35	$86,637	439	$61,771	313	$29,010	147	$89,794	455	$55,850	283	$323,062	1,637
Indirect (Customers)	$0.08	$25,020	296,604	$16,183	191,841	$6,627	78,562	$20,428	242,162	$14,628	173,413	$82,886	982,582
IT5 - Telecommunications													
Number of Employees	$167.79	$73,659	439	$52,518	313	$24,665	147	$76,344	455	$47,484	283	$274,670	1,637
Indirect (Customers)	$0.07	$21,273	296,604	$13,759	191,841	$5,634	78,562	$17,368	242,162	$12,437	173,413	$70,471	982,582
Total IT		$1,626,366	1,484,066	$1,056,994	959,924	$448,890	393,168	$1,400,171	1,211,962	$973,843	867,767	$5,506,264	4,916,887

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(1)
Note:
Source:

TEMPLATE EIGHT: IMPLEMENTATION PLAN

Milestone	Start date	End date	Responsible party	Status[1]
UCG Integrated	8/1/97	9/1/98	IT and UCG (RK/JM)	S
I.T. Strategy	4/1/98	Unknown	All Atmos Management	S

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(1) C = complete
(1) S = started but not yet complete
Note: N = not yet begun
Source: A = awaiting completion of other tasks

TEMPLATE NINE: SERVICE PROVIDER CHECKLIST

- [ ] All service agreements signed
- [ ] I understand how I will charge for my services
- [ ] I understand how and when I will report these measures
- [ ] I have identified all changes required for implementation
- [ ] I have laid out the measures and milestones of a successful implementation
- [ ] I am prepared to implement on October 1, 1998

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(1)
Note:
Source:

Template One: Shared Services Product and Customer Definitions Background

IT1 - Enterprise Servers Support

- Coordinate technology reviews and standards definition with the BU's
- Administer mainframe, midrange, and LAN environments
- Administer database environments
- Process applications
- Manage system security, change control and disaster recovery
- Administer Email systems (Internal and Internet)
- Provide Internet access

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- Host Web pages for Internet and Intranet

(1)
Note:
Source:

Template One: Shared Services Product and Customer Definitions Background (cont'd)

IT2 - Information Systems Support

- Facilitate Business Unit identification of application system requirements
- Facilitate identification of technology applications
- Publish consolidated Information Technology Plan for Atmos Energy Corporation
- Assist with new product feasibility studies, RFI's, RFP's and development
- Provide 7 by 24 production system support
- Provide system modification and enhancement services

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- Install vendor supplied software system upgrades

(1)
Note:
Source:

I.T. PROVIDES 100% OF SHARED SERVICES PC SUPPORT (IT3) NEEDS

- Review new and updated technology and recommend standards
- Define standard configurations, including software drivers and service packs
- Manage PC and office equipment procurement process, tracking software license compliance and maintaining a inventory of PC and office equipment
- Facilitate I.T. training by setting curriculum, negotiating services, evaluating providers, maintaining the training environment, customizing industry standard materials, developing company specific IT training and providing one-on-one training
- Install, upgrade and/or relocate PC hardware/software and office equipment
- Coordinate with vendors on PC application software
- Setup/test/support PC audio/visual equipment
- Consult with users on PC and office equipment requirements, budgets, technology and usage
- Third level problem resolution
- Review PC users' applications for design suggestions and problem resolution

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(1)
Note:
Source:

I.T. PROVIDES PC SUPPORT (IT3) TO BUSINESS UNITS (1)

- Coordinate technology reviews and standards definition with the BU's
- Define standard configurations
- Manage PC procurement process
- Assist Employee Development with BU specific I.T. training
- Track software license compliance
- Prepare and evaluate RFP's and negotiate contracts for purchase and maintenance of office equipment with the involvement of the I.T. Standards Committee

- For the remaining functions the PC Support group is providing backup and acts as a secondary source of information.

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(1) Based on number of PC related incidents for Fiscal Year '97. Support provided by PC support group for Energas - 4%, GGC - 10%, TransLa - 43%, WKG - 17%. For UCG it is projected to be 25%.
Note:
Source:

I.T. PROVIDES 100% OF SHARED SERVICES HELPDESK SUPPORT (IT4) NEEDS

- Provide single point of contact for problem reporting
- Document problem reports and resolutions
- Resolve Level One and Level Two problems
- Escalate Level Three problems to appropriate personnel
- Contact appropriate vendor for hardware resolution
- Maintain problem resolution database
- Provide access to an I.T. solution knowledge base
- Retain "ownership" of all problems

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(1)
Note:
Source:

I.T. PROVIDES 100% OF HELP DESK SUPPORT (IT4) TO BUSINESS UNITS

- Provide single point of contact for problem reporting
- Document problem reports and resolutions
- Resolve Level One and Level Two problems
- Escalate Level Three problems to appropriate personnel
- Contact appropriate vendor for hardware resolution
- Maintain problem resolution database
- Provide access to an I.T. solution knowledge base
- Retain "ownership" of all problems reported to the Help Desk

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(1)
Note:
Source:

I.T. PROVIDES 100% OF SHARED SERVICES TELECOMMUNICATIONS SUPPORT (IT5) NEEDS

- Evaluate and recommend standards
- Prepare and evaluate RFP's, and negotiate contracts for telecommunications services and equipment (long distance, local access, credit cards, frame relay, telephone switches, cellular telephones, pagers etc.)
- Implement and maintain telecommunications services and equipment
- Verify, code and monitor invoices for telecommunications services and equipment
- Maintain video conference services
- Maintain satellite services

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(1)
Note:
Source:

I.T. PROVIDES TELECOMMUNICATIONS SUPPORT (IT5) TO BUSINESS UNITS

- Coordinate technology reviews and standards definition with the BU's
- Prepare and evaluate RFP's, and negotiate contracts for corporate wide telecommunications services (long distance, frame relay, credit cards, etc.) with involvement of the I.T. Standards Committee
- Implement and maintain corporate wide telecommunications services
- Obtain and maintain radio licenses
- Assist with all Telecommunications needs as requested
  - Telephone systems down
  - Backup for remote updating of switches
  - Addition of phone circuits
  - Radio base station and circuit problems

- For the remaining functions the Telecommunications Support group is providing backup and acts as a secondary source of information.

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(1)
Note:
Source:

Information Technology Template Two: Budget Background

	Number of people	Labor - Exempt	Labor - Non-Exempt	Total Labor	Benefits	Overhead Allocations	Other	Total
I.T. Management	2	148,188	33,540	181,728	68,843	68,776	0	319,347
Information Systems Support	19	669,204	26,827	696,031	104,405	242,712	468,000	1,511,148
Data Center & IT Support	22	1,160,172	131,712	1,291,884	193,788	1,067,046	40,000	2,592,718
PC Support	3.5	189,031	0	189,031	28,355	112,448	15,000	344,834
Office Equipment	0	0	0	0	0	51,000	0	51,000
Help Desk	6.5	80,952	169,222	250,174	37,524	60,066	26,250	374,014
Telecommunications Support	3	163,001	0	163,001	24,449	125,758	0	313,208
	56	2,410,548	361,301	2,771,849	457,364	1,727,806	549,250	5,506,269

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(1)
Note:
Source:

ALLOCATION OF ENTERPRISE SERVERS SUPPORT TO BUSINESS UNITS

Based on Number of Customers

Expense	Percent Of Cost	Allocation Of Cost [1]	Direct [2] Allocation: Energas	GGC	TransLa	UCG	WKG
Mainframe Enterprise Server	27.6%	$747,068	$225,511	$145,859	$59,732	$184,118	$131,848
CIS Enterprise Server	49.0%	$1,326,047	$400,283	$258,900	$106,024	$326,811	$234,029
LAN Environment	23.4%	$631,375	$190,588	$123,271	$50,481	$155,605	$111,430
Total	100.0%	$2,704,490	$816,382	$528,030	$216,237	$666,534	$477,307
Cost per Customer per Year	$2.75						

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(1)
Note:
Source:
(1) Costs allocated based upon review of expense budget items
(2) Direct allocation based on number of customers

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ALLOCATION OF INFORMATION SYSTEMS SUPPORT TO BUSINESS UNITS

Based on Number of Customers

Expense	Percent Of Cost	Allocation Of Cost	Direct [1] Allocation: Energas	GGC	TransLa	UCG	WKG
Application System Support	100.0%	$1,622,920	$489,960	$316,794	$129,834	$400,050	$286,282
Total	100.0%	$1,622,920	$489,960	$316,794	$129,834	$400,050	$286,282
Cost per Customer per Year	$1.65						

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Note:
(1) Direct allocation based on number of customers
Source:

ALLOCATION OF PC SUPPORT TO BUSINESS UNITS
Based on Number of PC's and Customers

User	Number of PC's	Percent of Total Number of PC's	Direct Allocation	Direct and Indirect Allocation: Energas	GGC	TransLa	UCG	WKG
Energas (1)	168	13.9%	$59,460	$59,460				
GGC (1)	93	7.7%	$32,938		$32,938			
TransLa (1)	64	5.3%	$22,672			$22,672		
UCG (1)	242	20.0%	$85,554				$85,554	
WKG (1)	136	11.2%	$47,910					$47,910
Shared Services (2)	289	23.9%	$102,237	$30,861	$19,961	$8,174	$25,197	$18,044
Call Center (2)	218	18.0%	$76,998	$23,243	$15,033	$6,156	$18,977	$13,589
Total	1210	100.0%	$427,769	$113,564	$67,932	$37,002	$129,728	$79,543

Direct Cost Per PC Per Year $353.53 Shadow box

Indirect Cost Per Customer Per Year $0.18

(1)
Note:
Source:
(1) Direct allocation based on number of PC's
(2) Indirect allocation based on number of customers

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ALLOCATION OF HELP DESK SUPPORT TO BUSINESS UNITS

Based on Number of Employees and Customers

				Direct and Indirect Allocation				
User	Number of Employees	Percent of Total Number of Employees	Direct Allocation	Energas	GGC	TransLa	UCG	WKG
Energas (1)	439	21.3%	$86,637	$86,637				
GGC (1)	313	15.2%	$61,771		$61,771			
TransLa (1)	147	7.1%	$29,010			$29,010		
UCG (1)	455	22.1%	$89,794				$89,794	
WKG (1)	283	13.8%	$55,850					$55,850
Shared Services (2)	280	13.6%	$55,258	$16,680	$10,789	$4,418	$13,619	$9,752
Call Center (2)	140	6.8%	$27,629	$8,340	$5,394	$2,209	$6,809	$4,877
Total	2057	100.0%	$405,949	$111,657	$77,954	$35,637	$110,222	$70,479

Direct Cost Per Employee Per Year $197.35

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Indirect Cost Per Customer Per Year $0.08

(1)

Note:

Source:

(1) Direct allocation based on number of employees

(2) Indirect allocation based on number of customers

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ALLOCATION OF TELECOMMUNICATIONS SUPPORT TO BUSINESS UNITS

Based on Number of Employees and Customers

User	Number of Employees	Percent of Total Number of Employees	Direct Allocation	Direct and Indirect Allocation: Energas	GGC	TransLa	UCG	WKG
Energas (1)	439	21.3%	$73,659	$73,659				
GGC (1)	313	15.2%	$52,518		$52,518			
TransLa (1)	147	7.1%	$24,665			$24,665		
UCG (1)	455	22.1%	$76,344				$76,344	
WKG (1)	283	13.8%	$47,484					$47,484
Shared Services (2)	280	13.6%	$46,981	$14,182	$9,173	$3,756	$11,579	$8,291
Call Center (2)	140	6.8%	$23,490	$7,091	$4,586	$1,878	$5,789	$4,146
Total	2057	100.0%	$345,141	$94,932	$66,277	$30,299	$93,712	$59,921

Direct Cost Per Employee Per Year			$167.79
Indirect Cost Per Customer Per Year			$0.07

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(1)
Note:
Source:
(1) Direct allocation based on number of employees
(2) Indirect allocation based on number of customers

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Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request Dated July 16, 1999
DR Item 83 c
Witness: Betty Adams

Data Request:

83. Refer to Volume 2 of 10 of the Application, Tabs 2 and 4, the testimony of R. Earl Fischer and Betty L. Adams. To some extent, both witnesses address the issue of direct billed intercompany services and allocated service costs from Atmos's Shared Services Business Unit ("Shared Services") to Western and other Atmos business units:

    c. Provide Shared Services' cost allocation manual, if available. If none is available, describe the cost allocation process for the portion of the cost not directly billed to Western and provide copies of all internal policies and procedures relating to the allocation of costs from Shared Services to Western.

Response:

There is no formal manual discussing the allocation of Shared Service costs. Please refer to Response to DR 83 c - FR10(9)(u) Exhibit A: "Corporate Allocation Methodology" for a detailed description of the cost allocation process. Also, refer to the response to DR Item 34 c which describes the justification for each Shared Service Units' allocation method.

Response to DR 83 c - FR 10(9)(u) Exhibit A
Corporate Allocation Methodology

Shared Services Contracting Process

Effective October 1, 1999, Atmos implemented its shared services contracting process whereby each Shared Services Unit formally contracts with each Business Unit for services to be rendered during the upcoming fiscal year. These contracts specify the services or products to be provided and projected cost of each product to each Business Unit. This structure gives the Business Units the opportunity to review, negotiate, and agree to the terms of service being provided.

For fiscal year 1999, the actual expenses incurred by the Shared Services Units are being billed to the business units based each Shared Service Unit's overall projected distribution of costs among the business units as reflected in its contract. This process is the basis for the billing cost allocation for the Base Year and the Test Year. The resulting dollars billed to WKG are shown in Schedule 1 (Base Period) and Schedule 2 (Test Period).

Allocation of Non-Contracted Costs

Aside from the contracted service costs described above, certain other costs are allocated to the Business Units, as described below:

1. Shared Services Depreciation Costs - This represents depreciation of the general plant assets of Shared Service Units, which is allocated to the business units based on the Residual Factor.

2. Shared Services Taxes Other Than Income Taxes - This includes such other taxes as ad valorem taxes, franchise taxes, payroll taxes, etc., related to shared service assets and operations. These are spread to each business unit based on the residual factor.

3. Management Committee – This includes the expenses for the Executive Functions of Atmos. These costs are allocated to each business unit based on the residual factor for the fist two months of the base year and based on the average of the Shared Services Unit allocation of contracted costs for the final ten months of the base year.

Corporate Office Operation & Maintenance Direct Expense Methodology

Certain costs are not allocated, but rather are directly charged to the appropriate business unit when practical. Costs related to outside legal firms, insurance invoices, and other costs directly related to one business unit are coded directly to that business unit and are not included in the allocated costs from the Shared Service Units.