CASE NUMBER:

99.070

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 1
Witness: Burman

Data Request:

With reference to the response to Kentucky Public Service Commission Data Request (KPSC) 2-2(c), please explain in detail how the estimate for the affiliate transaction is determined, and provide a workpaper supporting the forecasted test year amount.

Response:

WKGR maintains two customer-owned gas storage fields. The historical average costs incurred on behalf of WKGR has been approximately $30,000 annually. This is an average cost which may vary from year to year.

This cost is incurred through periodic direct labor and material charges made by storage field technicians to unique accounts attributable only to this activity. The cost of utilities installed and incurred at these sites are directly coded to these accounts as well. A monthly assignment of indirect administrative overheads is also made. The average $30,000 annual cost is, therefore, a combination of labor, materials, utilities and administrative overhead expense. $30,000 is a nominal level of expense which does not affect Western's staffing requirements (less than the annual payroll cost associated with one storage field technician) or other planning requirements.

Absent conflicting information, and given the nominal level expense historically incurred, Western has assumed this continuing level of expense and a corresponding credit to expense in its budgeting.

See the response to AG #2 – DR Item 2 for a workpaper documenting historical charges in support of this estimate.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 2
Witness: Burman

Data Request:

2. With reference to the response to KPSC 2-2(a), please provide the schedule as requested.

Response:

See attached schedule.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 3 a, b
Witness: Donald P. Burman

Data Request:

1. With reference to the response to KPSC 2-4:

   a. Do the amounts presented in item (a) include only amounts paid out in claims and administrative costs? Do they include contributions to a trust fund?

   b. Does Western maintain an external trust fund such as a VEBA trust in which it is currently contributing cash towards its OPEB liability? If so, please provide the balance in that fund for each of the years shown in the response to KPSC 2-4 (a & b), and provide the annual amount contributed each year.

Response:

a. The amounts presented in KPSC 2-4(a) include amounts paid in claims and administrative costs, less retiree contributions. They do not include contributions to an external trust fund.

b. In September 1999, Atmos funded a VEBA trust with $2,879,616 for WKG's OPEB liability.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 4
Witness: David H. Doggette

Data Request:

4. With reference to the response to KPSC 2-9(a), if there are no similar amounts for 96, 97 and 98, how does the Company assure itself that the 36.25 percent factor is a reasonable amount? Please explain fully.

Response:

Please see the response to KPSC 3-29. Also, refer to the responses to the clarifying questions posed in AG SDR-5

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 5
Witness: David H. Doggette

Data Request:

5. With reference to the development of the 36.25 percent factor and the supplemental response to KPSC 1-10:

   a. Are the projects that equate to 36.25 percent of the 1999 maintenance budget additional projects to those which are anticipated and presented on Exhibit DHD-1, page 2, or are they the same projects that are presented on lines 36 through 41 of Exhibit DHD-1?

   b. Was the 36.25 percent factor used as a proxy for maintenance and system improvements based upon the identifiable projects in the maintenance budget?

   c. Do all the projects listed in the supplemental response to KPSC 1-10 belong in the classification of maintenance, system improvements or both?

   d. Given that the 36.25 percent factor is applied to FY 1999 capital budget amounts as the baseline, please explain fully how the FY 1999 capital budget was developed. Indicate whether it was developed using the bottom-up approach or FY 1998 as capital budget a baseline.

   e. Doesn't the FY 1999 capital budget include the costs associated with similar maintenance and improvement projects? Explain fully why the Company believes that the projects in the maintenance and improvement section of the FY 1999 budget are not representative of the projects to be performed during FY 2000. Provide workpapers and documentation that demonstrate this assumption.

Response:

a. The contemplated expenditures that are the projected increase in system maintenance and improvements are presented in DHD-1, Page 2, Lines 35 through 73, under the column titled "Projects".

b. Yes. Because the exact nature and extent of the projects were not known at the time the forecasted budget was developed, the approximate amount of the projects was distributed across all accounts showing activity in FY 1999 in the System Maintenance and System Improvements categories. The percentage of the increase was determined and applied against the budgeted amounts in the accounts shown in

FY 1999, assuming that the capital construction in FY 2000 would be of a similar nature.

Western has been developing its FY 2000 Capital Budget in the interim since the original forecast and data request responses have been submitted. Based on the latest information submitted by appropriate employees, attached is AG SDR-5, Schedule 1. This schedule shows FY 1999 projects that were budgeted over and above the normal requests for recurring "blanket" construction expenditures. These are Specific Projects which are identified as necessary, non-recurring capital expenditures.

On the left side of the schedule the amounts for FY 1999 are shown and reduced by the overheads to determine the direct costs, which are $305,895. On the right side of the Schedule are Specific Projects proposed in the Capital Budget for FY 2000. These are already stated at direct cost amounts and total $1,098,637. The comparison of Specific Projects is made by reducing the FY 2000 amount by the comparable direct cost of Specific Project in FY 1999. By comparing the remainder, it shows a need for $ 793,742 as the additional funding required in FY 2000. This remaining amount is $ 88,526 more than the amount requested in the forecast.

As stated in KPSC 3-29, Western believes that we can still maintain the safety and reliability at the forecasted capital budget level.

c. Replacement projects such as those are considered as System Maintenance.

d. The Fiscal Year 1999 capital budget was prepared in the "bottom-up" manner described in the testimony of Mr. Doggette in the section on Capital Budgeting Process starting at Page 3, Line 21.

e. Some costs in FY 1999 are of a similar nature. They were accounted for in developing the forecast for capital construction activity. Please see response in b. above, and the attached AG SDR-5, Schedule 1.

FY1999 vs. FY2000 System Maintenance & System Improvements **AG SDR- 5, Schedule 1**

FY 1999 — **Numbers Include Overheads**

Specific Projects		
700' 2" Main Replacement-Owensboro	$	2,800
Replace 2" Field Lines	$	5,962
700' HP Trans Line Replacement	$	9,476
AM/FM Map Conversion	$	100,000
Customer EFM-Statewide	$	98,000
-Less Reimbursement	$	(26,400)
Liberty Sta. 6" Valve Replacement-Madisonville	$	5,959
Hwy 121 Relocation-Mayfield	$	61,374
-Less Reimbursement	$	(31,765)
4" T Line Replacement-Mayfield	$	49,468
Uprate Commerce Park-Hopkinsville	$	17,000
Skyline Drive Relocation-Hopkinsville	$	118,505
Main Relocation N. Race St.-Glasgow	$	52,848
-Less Reimbursement	$	(20,850)
2" Replacement, Skyline Dr.-Hopkinsville	$	5,391
Install Reg. Stations, Commerce Park-Hopkinsville	$	131,000
Reg. Station Replacement-Elkton	$	23,500
Relocate 1100' of 2" Plastic Pipe	$	12,749
	$	615,017

FY 2000 — **Numbers Do Not Include Overheads**

		Specific Projects
$	13,500	State Hwy Relocation
$	34,116	Town Border #3 Relocation
$	16,667	Commerce Park Upgrade
$	25,500	Shelbyville Cast Iron Replacement
$	12,482	Moreland Tie-back Pressure Improvement
$	19,500	Danville Sreamland Improvement
$	12,400	Campbellsville ByPass
$	232,620	Line 133 Upgrade
$	18,000	Lancaster Purchase Station
$	5,000	Mt. Eden Purchase Station
$	2,000	Lebanon TBS Fencing
$	10,000	Lancaster Ground Bed Relocation
$	46,750	Rumsey (Calhoun) Bridge Relocation
$	44,483	Hwy 231 Relocation
$	(13,997)	-Less Reimbursement
$	13,000	Replace Habit Odorant System
$	70,000	Hwy 41 Relocation
$	55,272	Hwy 91 Relocation
$	12,000	Ground Bed Replacement-Sharp Avenue
$	16,530	Blandville Road-Paducah
$	7,500	Husband Rd. Ground Bed Replacement
$	22,000	EFM for customers
$	57,200	EFM for customers
$	21,119	Odorize 12"-Midwest
$	20,000	Uprate Hickory lines for load
$	54,000	Optimize gathering lines
$	100,002	Map conversion project
$	17,770	Bon Harbor Rectifier Bed
$	31,030	Relocate Habit Dehydrator
$	50,260	Hoffman #1 Well Workover
$	21,933	10" & 12" Leakage
$	25,000	Richards #1 Well Workover
$	25,000	McGregor #1 Well Workover
$	1,098,637	Estimated Direct Costs

Adjust for 1999 Overheads and Compare to FY 2000 Projection

Cost of FY 1999 Project	$	615,017
-Less 50.425% Overheads	$	310,122
Direct Costs	$	304,895

$	1,098,637	Estimated Direct Costs
$	304,895	-Less Comparable Projects From FY 1999
$	793,742	
$	**705,216**	***Amount Forecasted in FY 2000 Budget Projection***
$	**88,526**	**Amount NOT Included in FY 2000 Forecast**

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 6
Witness: David H. Doggette

Data Request:

6. Please provide the "Approved Authorization for Expenditures" for each of the projects listed in supplemental response to KPSC 1-10.

Response:

"Approved Authorization(s) for Expenditures" have not been issued for any FY 2000 projects. The "AFE's" are not requested until just prior to commencing construction in that fiscal year.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 7
Witness: Betty Adams

Data Request:

With reference to the response to KPSC 2-66, please provide a detailed explanation of the nature of the lawsuit settlement amortization, the excess property damage, and the prepaid liability amortization. Your response should also indicate the cause of the charges, the length of the amortization period, and indicate any Commission approvals for the amortization.

Response:

The company follows a policy whereas any lawsuit settlement greater than $50,000 is amortized over a 12 month period. This amortization is to provide a level amount of monthly expense, which eliminates large fluctuations from month to month. Due to the amount of the lawsuit settlement referenced in response to KPSC 2-66, this settlement is being amortized over a 5 year period, which started in October 1998 and will end in September 2003. The cause of the charges is the settlement of a lawsuit resulting from an incident involving natural gas in Danville, Kentucky.

The excess property damage amortization is for property damage insurance to cover the Company's real property, such as, buildings, equipment, furniture, pipe in the ground, etc., but does not include coverage of vehicles. This is a yearly policy paid in advance and amortized over a 12 month period.

The prepaid liability amortization is a policy to cover damages to 3rd parties. It is a self insured retention that is paid yearly in advance and is amortized over a 12 month period.

No Commission approvals were required for any of the amortizations.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 8
Witness: Betty Adams

Data Request:

With reference to the response to Attorney General Data Request (AG) 1-165:

a. Please identify the components and explain the nature of the costs which are being amortized over a 7-year period.

b. Please identify and explain how any one-time or non-recurring cost savings from the Atmos/United Cities merger have been passed back to customers or handled for ratemaking purposes in Kentucky.

c. Cite the Commission Order authorizing the recovery of merger-related costs.

Response:

a. The 7-year period amortization includes merger and integration costs such as investment banking fees, legal fees, consulting fees, filing fees, and relocation and severance costs. Western's portion of these costs represents 3% of the total, based on Western's level of severance costs relative to the severance costs incurred by Atmos' other business units. The bulk of the severance costs were incurred at United Cities where total employee levels were reduced by 52% as result of the merger.

b. The Company has not identified any material or significant one-time or non-recurring cost savings from the merger. It has identified significant ongoing cost savings related to integration of the merger resulting from employee reductions, restructuring of operations, and the combination of systems. See Western's response to Supplemental Response to KPSC #1 DR Item 6 for a discussion of the ongoing benefits of the merger in conjunction with all of Western's efficiency and productivity improvements.

c. The Company does not assert that a Commission Order was issued specifically authorizing the recovery of merger-related costs. Western is seeking recovery of these costs because they were incurred to achieve net cost savings which are being passed to Western's customers.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 9
Witness: Doggette

Data Request:

9. With reference to the response to AG 1-166:

a. Did the Commission approve the changes requested by the Commission Staff? If so, please cite the Order.

b. The response to KPSC 1-77 shows the $319,730 expected savings. Please provide expected savings after reflecting the Commission Staff's changes to the program. Please include supporting documentation in your response.

Response:

a. The order attached to AG#1 – DR Item 166 is the final order and incorporates some of the Staff's changes but, as indicated in the order, also incorporates the amended program re-submitted by Western.

b. Western had just obtained the order when it was submitted in DR 166. Since the order incorporates Western's amended program in concert with the Staff's changes, we are now reasonably optimistic that the original $319,730 in savings can still be achieved. These savings were documented in our response to KPSC #1 DR Item 77.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated September 20, 1999
DR Item 10
Witness: Betty Adams

Data Request:

With reference to AG 1-169, please explain the negative depreciation expense during May 1999.

Response:

Depreciation expense associated with CIS/Banner, IT Strategy/Oracle and related productivity improvements had been captured by Shared Services and allocated to the utility business units through the Shared Services billing during the start-up phase. Upon substantial completion of the transition to full implementation, May 1999, the year-to-date depreciation expense was reversed from Shared Services and recorded by the utility business unit. AG 1-163 indicates the June 1, 1999 implementation date of CIS/Banner, the same date Western began using the new Oracle financial systems.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Request For Information
DR Item 11
Witness: Donald Burman

Data Request:

11. With reference to the response to AG 1-198 and 1-199:

a. By setting pensions expense to $0, does the Company believe that pensions expense, for ratemaking purposes, should be based upon the amount contributed to the pension plan? Please explain.

b. If pensions expense is set at $0 when the expense level is negative, will the Company agree to give ratepayers a credit when the expense becomes positive? If no, please explain.

Response:

11(a.) No. The amount the company actually contributes to the pension plan is but one element of pension accounting to be recognized on the company's books.

The company follows FAS 87 for pension accounting purposes and recognizes pension costs on an accrual basis, such that financial statements match costs with the period in which employee service is rendered. Similarly, for ratemaking purposes, the company follows the accrual method to the extent that pension expense is positive, thus funding today's pension costs from today's rates.

Other pension cost elements include: the discount interest cost associated with payment of future benefits, actual return on plan assets, gains and losses associated with changes in projected benefit obligation or plan assets resulting from experience different than projected, service cost for today's employees, amortization of unrecognized prior service cost, and transition obligations at the date of implementation of FAS 87.

Thus, recognition for ratemaking purposes only the amount of cash contribution made to the pension plan may understate in today's rates the cost of providing pensions to today's employees and effectively shift that burden to future ratepayers.

11(b.) No. If the company were to simply "give ratepayers a credit" when the per-books pension expense turns positive, it would under-collect pension expense for that future period.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 12 a, b, c, d
Witness: Donald P. Burman

Data Request:

12. With reference to the attachment to AG 1-197:

a. Please explain what $(11,703,506) amount in the "Balance Sheet Accrued (Prepaid) Cost as of 10/1/98" column represents.

b. Please provide a breakdown showing the year-by-year accumulation of $(11,703,506) that indicates the amount collected in rates, the benefits paid out, and the amount contributed to the pension plan fund.

c. Please provide the accrued/(prepaid) cost as of the end of the forecasted period. Include workpapers.

d. Please provide the level of accumulated deferred income taxes associated with the $(11,703,506), and the end of the forecasted period amount. Indicate if the deferred taxes have been included in rate base.

Response:

a. The $(11,703,506) Balance Sheet Accrual (Prepaid) Costs as of 10/1/98 represents net prepaid pension cost of the WKG Retirement Plan recognized under FAS132. The actuarial computation is summarized below and in the "1998" column of part (b) below.

Projected Benefit Obligation at 9/30/98	$(35,782,569)
Fair Value of Plan Assets at 9/30/98	60,078,505
Funded Status	24,295,936
Unrecognized prior service cost	1,324,229
Unrecognized net gain	(13,916,659)
Prepaid Pension Cost (net amount recognized)	$11,703,506

b. The SFAS No. 87 disclosures for the WKG Retirement Plan reflected in Atmos' audited financial statements for the five years ended September 30, 1998 are as follows:

	1998	1997	1996	1995	1994
			(In thousands)		
Projected benefit obligation	(35,783)	(36,293)	(35,673)	(31,642)	(28,328)
Plan assets at fair value	60,079	53,289	46,478	42,216	37,409
Funded status	24,296	16,996	10,805	10,574	9,081
Unrecognized prior service cost	1,324	3,976	4,829	2,855	3,378
Unrecognized net gain	(13,916)	(10,065)	(4,361)	(2,468)	(1,442)
Prepaid pension cost	11,704	10,907	11,273	10,961	11,017
Net periodic pension cost (benefit)	(1,278)	(22)	(312)	56	116

The amount collected in rates was the net periodic pension cost (benefit).

c. The accrued/(prepaid) cost is an actuarially computed amount consisting of several components and determination of such amount as of 12/31/2000 would require an actuarial study.

d. The accumulated deferred income tax associated with the $11,703,506 prepaid pension cost at 9/30/98 is computed below:

	Dr/(Cr)
Pension Asset – WKG	(11,703,506)
Rate	38%
Included in Deferred Liability	(4,447,333)

The prepaid pension cost at 12/31/2000, the end of the forecasted test period, is not available without an actuarial study. The related deferred taxes could be computed at 38%. Estimated accumulated deferred income taxes, from all sources including pensions, at 12/31/2000 are included as a reduction to rate base on FR 10(10) (b)1, Schedule B-1, Sheet 2 of 2, line 7.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Request For Information
DR Item 13
Witness: Donald Burman

Data Request:

13. With reference to the response to AG 1-199, reference is made to cases in Michigan and FERC. Subsequent to the dates of the cited orders, please explain how pensions expense has been set for ratemaking in those jurisdictions when the pensions expense per books is negative.

Response:

13. Subsequent to the dates of the cited orders, when the pension expense per books was negative, pension expense was set to zero for ratemaking purposes for both Michigan Consolidated Gas Company (MichCon) in Michigan and for Colorado Interstate Gas Company (CIG) under its FERC rates.

MichCon implemented the zero pension expense for ratemaking pursuant to the Michigan Public Service Commission's order in Case No. U-8812.

CIG's case was settled subsequent to the Hearing Examiner's order and the settlement cost of service included a zero amount for pension expense, according to CIG Witness Palazarri.

No additional cites were found for either MichCon or CIG for negative pension expense.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 14
Witness: Betty Adams

Data Request:

With reference to the response to AG 1-206, Schedule A, pages 1 and 3, please provide documentation supporting the amounts in the "Total Payroll" column.

Response:

Please see Schedule 1 attached for documentation of Schedule A, page 1, Base Year, "Total Payroll" in response AG 1-206.

See KPSC 3-50, Schedule 1A documenting the "Total Payroll" column of Schedule A, page 3, Forecasted Year in response AG 1-206. Also note that in KPSC 3-50, this schedule was revised per the question. See KPSC 3-50, Schedule A, for the revised numbers, with the documentation included in KPSC 3-50 in Schedule 2A.

Administrative

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	60,719	88,659	64,940	60,727	54,773	65,635	59,854	58,416	60,204	60,414	60,516	60,517	755,374
CAPITAL/OTHER LABOR	1,977	6,237	34,353	24,459	12,882	16,033	11,651	11,479	11,651	11,651	11,742	11,740	165,855
TOTAL LABOR	62,696	94,896	99,293	85,186	67,655	81,668	71,505	69,895	71,855	72,065	72,258	72,257	921,229

Tech Services

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	79,466	67,946	73,982	70,959	60,888	69,936	60,373	60,480	61,129	60,936	61,015	61,168	788,278
CAPITAL/OTHER LABOR	19,194	31,606	77,816	32,052	41,156	26,730	38,080	38,108	38,285	38,351	38,372	38,416	458,166
TOTAL LABOR	98,660	99,552	151,798	103,011	102,044	96,666	98,453	98,588	99,414	99,287	99,387	99,584	1,246,444

West Region Administration

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	17,615	15,927	17,444	20,979	18,153	18,692	20,914	20,914	21,087	21,087	21,087	21,087	234,986
CAPITAL/OTHER LABOR	4,216	4,604	13,354	4,931	7,359	3,523	11,196	11,196	11,354	11,354	11,354	11,353	105,794
TOTAL LABOR	21,831	20,531	30,798	25,910	25,512	22,215	32,110	32,110	32,441	32,441	32,441	32,440	340,780

Madisonville Operations

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	84,875	70,712	82,613	83,228	71,727	83,295	77,060	77,119	77,187	77,301	77,403	77,403	939,923
CAPITAL/OTHER LABOR	19,192	34,050	74,434	25,631	35,312	21,014	36,758	36,786	36,802	36,863	37,010	37,009	430,861
TOTAL LABOR	104,067	104,762	157,047	108,859	107,039	104,309	113,818	113,905	113,989	114,164	114,413	114,412	1,370,784

Owensboro Operations

Schedule 1

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LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	99,400	86,176	94,029	95,993	85,604	95,124	84,594	84,783	84,875	84,444	85,151	85,400	1,065,573
CAPITAL/OTHER LABOR	19,903	33,982	83,229	27,672	37,224	21,646	37,741	37,815	37,851	37,691	37,969	38,064	450,787
TOTAL LABOR	119,303	120,158	177,258	123,665	122,828	116,770	122,335	122,598	122,726	122,135	123,120	123,464	1,516,360

Paducah Operations

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	84,909	72,645	81,787	87,141	79,467	84,048	67,588	67,588	69,043	69,176	69,309	69,369	902,070
CAPITAL/OTHER LABOR	15,543	27,723	69,411	15,644	23,035	13,937	25,815	25,815	26,508	26,558	26,608	26,629	323,226
TOTAL LABOR	100,452	100,368	151,198	102,785	102,502	97,985	93,403	93,403	95,551	95,734	95,917	95,998	1,225,296

East Region Administration

LABOR RECAP

Schedule 1

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	20,815	18,595	20,364	18,711	17,803	20,473	19,394	19,394	19,567	19,567	19,676	19,676	234,035
CAPITAL/OTHER LABOR	4,990	5,437	15,685	5,438	6,346	(990)	7,434	7,434	7,534	7,534	7,564	7,565	81,971
TOTAL LABOR	25,805	24,032	36,049	24,149	24,149	19,483	26,828	26,828	27,101	27,101	27,240	27,241	316,006

Bowling Green Operations

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	138,603	120,283	127,965	122,637	106,783	126,990	118,963	119,167	119,436	119,632	118,398	120,047	1,458,904
CAPITAL/OTHER RECAP	17,579	44,595	106,722	40,047	53,721	30,765	70,505	70,604	71,947	70,988	70,265	71,251	718,989
TOTAL LABOR	156,182	164,878	234,687	162,684	160,504	157,755	189,468	189,771	191,383	190,620	188,663	191,298	2,177,893

Danville Operations

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	120,484	93,677	108,636	100,450	84,665	94,745	95,948	96,180	96,610	96,713	96,894	96,894	1,181,896
CAPITAL/OTHER LABOR	5,751	28,346	74,218	25,898	37,170	22,977	55,547	55,663	55,892	55,957	56,046	56,045	529,510
TOTAL LABOR	126,235	122,023	182,854	126,348	121,835	117,722	151,495	151,843	152,502	152,670	152,940	152,939	1,711,406

Total Company

Schedule 1

LABOR RECAP

	ACTUAL						BUDGET						
	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE LABOR	706,886	634,620	671,760	660,825	579,863	658,938	604,688	604,041	609,138	609,270	609,449	611,563	7,561,041
CAPITAL/OTHER LABOR	106,345	195,580	572,222	201,772	254,205	155,635	294,727	294,900	297,824	296,947	296,930	298,070	3,265,157
TOTAL LABOR	813,231	830,200	1,243,982	862,597	834,068	814,573	899,415	898,941	906,962	906,217	906,379	909,633	10,826,198

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 15
Witness: Donald P. Burman

Data Request:

15. According to the response to AG 1-208 the level of SFAS 106 expense included in the forecasted test year expenses is $1,433,000, however, the response to KPSC 2-4 indicates the annual OPEB cost is $1,583,200. Please explain the difference. If the difference is due to the application of the O&M percentage, please explain why that percentage differs from the percentage used for the payroll. Include any supporting data.

Response:

The net periodic postretirement benefit cost for WKG for the year ended September 30,1999 as computed by the actuary, recorded on the company's books and reflected in its audited financial statements was $1,583,200. The forecasted expense for the year 2000, the test year, is approximately the same amount, not the $1,433,000 which was incorrectly reported in AG 1-208.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 16
Witness: Donald P. Burman

Data Request:

16. With reference to the response to AG 1-221:

a. Please provide a workpaper showing the buildup of the $5,511,500 OPEB liability. Indicate the OPEB amount allowed in rates, the amount paid out in claims and administrative costs, etc.; and the amount contributed to the OPEB external fund.

b. Please update the OPEB liability to reflect the balance as of the end of the forecasted test year.

c. Please provide the level of accumulated deferred income taxes associated with the $5,511,500 OPEB liability, and the similar amount as of the end of the forecasted test period. Indicate if the deferred taxes were included in rate base.

Response:

a. The OPEB liability as recorded and reported in response to AG 1-221 of $5,511,500 was an estimate based on preliminary actuarial work. The results of the final Actuarial Study for Western Kentucky Gas that details the components as of September 30, 1998 are set forth below:

Change in Plan Assets:

	9/30/98 (000's)
Fair Value of Plan Assets at Beginning of Year	-
Actual Return on Plan Assets	-
Employer Contribution	$ 720.20
Plan Participants' Contribution	114.00
Benefits Paid	(834.20)
Fair Value of Plan Assets at End of Year	-
Funded Status	(11,785.40)
Unrecognized Transition Obligation	5,290.20
Unrecognized Prior Service Cost	808.60
Unrecognized Net (Gain) or Loss	204.70
(Accrued)/Prepaid Postretirement Benefit Cost	$ (5,891.30)

Net Periodic Postretirement Benefit Cost	$ 1,430.40
Amount contributed to the OPEB external fund	$ 0.00

b. The OPEB liability recorded in accordance with SFAS 106 is an actuarially determined amount and an actuarial study is not available for the forecasted test year. The forecasted test year assumed OPEB costs in line with the base year.

c. Calculation of accumulated deferred income taxes associated with the final OPEB liability of $5,891,300 is as follows:

	Dr/(Cr)
Accrued postretirement benefit cost at 9/30/98	$5,891,300
Rate	38%
Included in deferred tax liability	$2,238,694

As indicated in b above, the OPEB liability at the end of the forecasted test year is assumed similar to the base year. The deferred taxes computed at 38% are included in rate base.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 17
Witness: Betty Adams

Data Request:

With reference to the response to AG 1-217:

a. Please provide the level of amortized injuries and damages included in the forecasted test period. Separately identify each claim being amortized and indicate when the amortization ends.
b. Please state the basis upon which claims over $50,000 are deferred and amortized.
c. Is the General Liability Reserve only used to hold funds relating to injuries and damages? Please identify the other components of the reserve and the associated amounts that makeup the $455,000 balance.

Response:

a. The total amount included in the forecasted period for amortized injuries and damages is $418,672. This is detailed below:

Lawsuit Settlement	$ 189,789	Started 10/98 - Ends 09/2003
Excess Property Damage Ins	44,334	Ends 09/2000
Prepaid Liability Ins	184,549	Ends 06/2000
	418,672	

Please note that both the excess property damage insurance and the liability insurance are 12 month policies renewable annually.

b. Please see response to AG 2-7 for an explanation of how claims over $50,000 are handled.
c. Yes, the reserve identified is only used to hold funds relating to injuries and damages and therefore there are no other components associated with this amount.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 18
Witness: Betty Adams

Data Request:

With reference to the response to AG 1-217(d), please clarify the response. Does the response mean that other reserve accounts have been included (either as an addition or deduction) in rate base but not the pension reserve. Please identify the various reserve accounts and indicate whether they are excluded from or included in rate base.

Response:

The response in AG 1-217(d) should have read "Only the pension expense credit has been excluded for ratemaking purposes". Please see KPSC 2-67 for a detailed explanation of this adjustment. No reserve accounts, including the pension reserve, have been included or excluded in the rate base, therefore there have been no adjustments made for ratemaking purposes for any reserves.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 19 (a &b)
Witness: Pat Reddy

Data Request:

With reference to the response to AG 1-235:

a. If the National Bank of Texas amount is related to fees for a credit facility for the 8/7/98 to 8/6/99 period, and was being amortized over the life of the facility, why is there still a balance during the forecasted test year? When does the amortization end?
b. Please explain how the fees relating to the National Bank of Texas credit facility is reflected in the cost of capital calculation by the Company.

Response:

a. The commitment and arrangement fees included in the short term debt capital structure are associated with the 364-day revolver established through NationsBank of Texas which has now merged into Bank of America. We do not have any association with "National Bank". This arrangement is renewed annually and is the backstop for the Company's commercial paper program. This fee is prepaid annually and amortized over the 12 month life of the arrangement.
b. These fees are reflected in the cost of capital as one of the components of the cost of short term debt, please refer to Schedule J-2, Volume 10, Tab 10 of the original filing.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 19 (c)
Witness: Betty Adams

Data Request:

With reference to the response to AG 1-235:

c. With reference to Oracle Data Base Main. and CIS Project, if these costs are related to maintenance contracts and technical support contracts which are being amortized, why do the balances fluctuate rather than steadily declining? Identify the total costs incurred for each of these items and provide the monthly amortization amount.

Response:

a. The prepaid balances were projected using two years historical information as a guide. During these historical years the balances did fluctuate due to the amortization and additional costs being booked. After further analysis, these accounts should have reflected the information shown below.

The Oracle Data Base Main. is a prepayment of a three year maintenance agreement in the amount of $235,390, which was booked to division 02. Westerns' portion is 16.657% or $39,209. The total monthly amortization amount is $ 8,025 of which Westerns' portion is 16.657% or $1,337. This amortization will end January 2000. The maintenance agreement will then be billed and expensed quarterly.

The CIS Project is a prepayment of a three year maintenance agreement for the billing system in the amount of $974,250, which was booked to division 02. Westerns' portion is 16.657% or $162,281. The total monthly amortization amount is $27,063 of which Westerns' portion is 16.657% or $4,508. This amortization will end December 1999. The maintenance agreement will then be billed annually, booked as a prepaid and amortized over the 12 month life of the agreement. The estimated total cost for the new contract is $300,000 of which Westerns' portion will be $49,971. The monthly amortization, based on the above estimate, will be $25,000 of which Westerns' portion will be 16.657% or $4,164.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 20
Witness: David H. Doggette

Data Request:

20. With reference to the response to AG 1-201, the referenced response indicates that "... budgeted additions are projected as a net amount less retirements" and that "Western does not budget for plant retirements since they are not known at the time of budget preparation".

   a. If Western does not budget for retirements what do the amounts in the "Retirements" column of Schedule B-2.2 pages 1 through 3 represent?

   b. Please explain how the budgeted additions can be projected net of retirements when the projected balance is based upon the applying the inflation and other cost rates to the previous year's balance.

Response:

20.) Western wishes to clarify that the referenced data requests and Western's responses, that is AG 1-201 and by association KPSC 1-35c, are in relation to the forecasted period. The forecasted period is provided in FR 10(10)(b)2.2, Volume 10 of 10, Tab 2, Schedule B-2.2, sheets 4 through 6 of the filing.

a.) The amounts in the "Retirements" column of Schedule B-2.2 pages 1 through 3 represent base period six months of actual retirements. Please refer to the response to KPSC 1-35b., along with its attachments, pages 19 through 21, for a complete detail listing of the retirements and transfers included in the base period.

b.) For further clarification, the phrase "...projected as a net amount less retirements..." should have been "...projected as an amount not inclusive of retirements...".

ATMOS ENERGY CORPORATION
KPSC Data Request #2 Dated Aug. 19, 1999
Data Request 2a.

Intercompany Transactions
WKGR Receivable from Western

Fiscal Year	Amount
1995	28,722.63
1996	33,994.68
1997	33,569.44
1998	15,554.01
1999	36,380.14

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 21
Witness: David H. Doggette

Data Request:

21. With reference to the response to KPSC 1-10, an explanation is given for the 50 percent overhead rate. Please provide similar data for FY 1996 through 1998.

Response:

The overhead percent and allocation amounts for 1996 through 1998 are shown. Although overhead percentage has increased each year, the total for the allocation amount combined with capital budget have been reduced each year.

	Fiscal Year 1996	Fiscal Year 1997	Fiscal Year 1998
Total Capital Budget	$17,770,374	$16,595,351	$10,194,434
Atmos A & G	$2,665,556	$2,987,163	$1,631,109
Western	$2,843,269	$2,655,256	$2,446,664
Total Allocation	$5,508,825	$5,642,419	$4,077,773
Percent Overhead	31%	34%	40%

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 22
Witness: David H. Doggette

Data Request:

22. Please provide a copy of the source of the 3 percent inflation rate as stated on page 10, line 15 of Mr. Doggette's testimony.

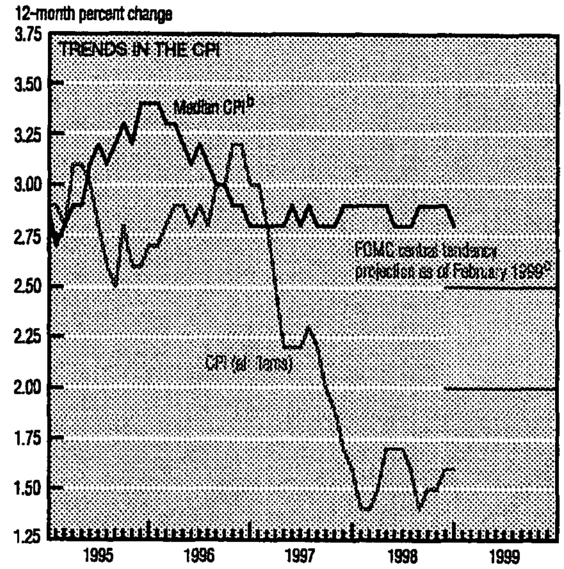
Response:

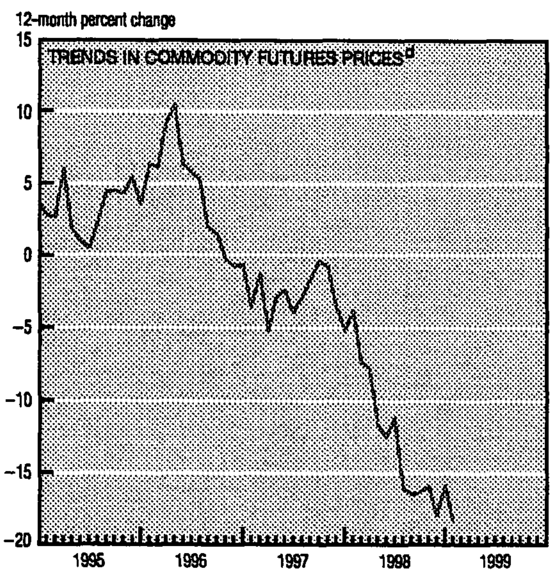
Western's Capital Budget is comprised of approximately 70% labor and 30% material expenditures. Wages were budgeted to increase at a rate of 4% annually for the forecast period as referenced in Ms. Adams' testimony on page 8, line 24. Western's budgeting is primarily based upon annual salary surveys related to our industry. Material prices are expected to rise at a rate equal to 2.5% for the forecasted period (source: Federal Reserve Bank). The combination of these two factors yields an inflation rate of 3.55%. Western has chosen to establish a more aggressive target of 3%.

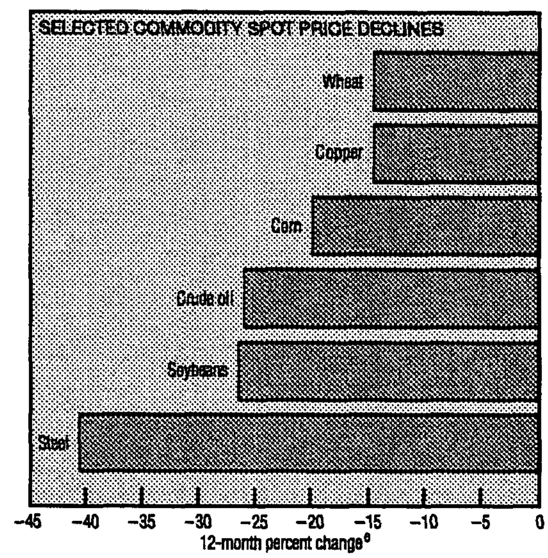
Inflation and Prices

January Price Statistics

	Percent change, last:				
	1 mo.[a]	3 mo.[a]	12 mo.	5 yr.[a]	1998 avg.
Consumer Prices					
All items	1.5	1.7	1.6	2.4	1.6
Less food and energy	0.7	2.1	2.3	2.6	2.5
Median[b]	1.3	2.2	2.8	3.0	2.9
Producer Prices					
Finished goods	6.6	2.8	0.9	1.1	–0.2
Less food and energy	–0.8	4.5	2.3	1.4	2.4







a. Annualized.
b. Calculated by the Federal Reserve Bank of Cleveland.
c. Upper and lower bounds for CPI inflation path as implied by the central tendency growth ranges issued by the FOMC and nonvoting Reserve Bank presidents.
d. As measured by the KR-CRB composite futures index, all commodities. Data reprinted with permission of the Commodity Research Bureau, a Knight-Ridder Business Information Service.
e. February 1998–February 1999.
SOURCES: U.S. Department of Labor, Bureau of Labor Statistics; the Federal Reserve Bank of Cleveland; the Commodity Research Bureau; and DRI/McGraw-Hill.

Consumer prices showed little movement in January, as the Consumer Price Index (CPI) inched up an annualized 1.5%, with much of the increase caused by higher food prices. After exclusion of the volatile food and energy components, the CPI showed even less movement, rising a mere 0.7% (annualized). The median CPI, an alternative measure of inflation, showed little change in January, rising an annualized 1.3%.

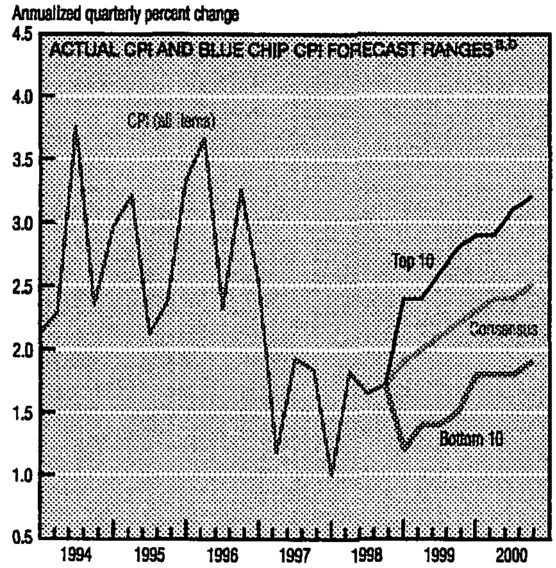
At its February meeting, the Federal Open Market Committee (FOMC) left the central tendency projection for the CPI unchanged at 2%–2.5% for 1999. The CPI is currently tracking nearly ½ percentage point under the lower bound of the central tendency, an indication that the FOMC expects consumer price pressure to increase significantly this year.

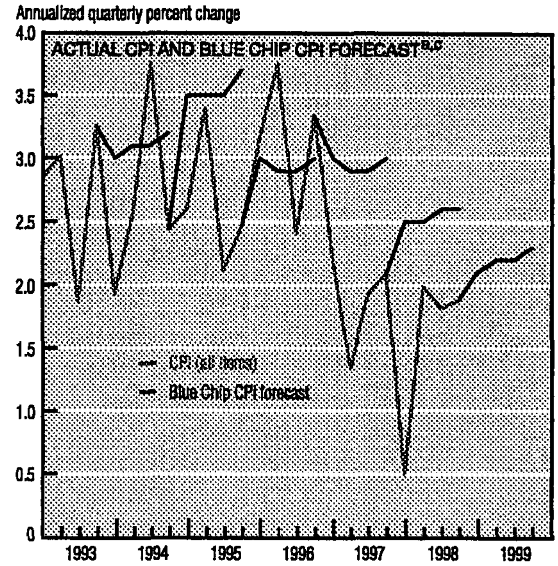
The futures price index of the Commodity Research Bureau (CRB) recently hit lows not seen since February 1975; the 12-month percent change in the index has been negative since November 1996, and its downward trend has accelerated during the past several years.

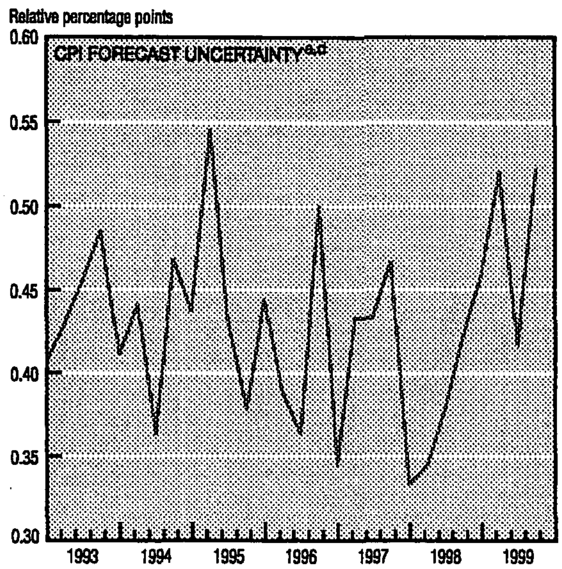
Economic weakness in Asia and Russia has reduced foreign demand for U.S. products while also creating fierce competition for the U.S. market. Since February 1998, the bushel spot price of soybeans has fallen 25%. Other agricultural products whose prices have dropped include corn (down more than 20%) and wheat (down 15%). Steel spot prices have been hit the hardest, as a flood of imported steel has driven the price down more than 40% in 12 months.

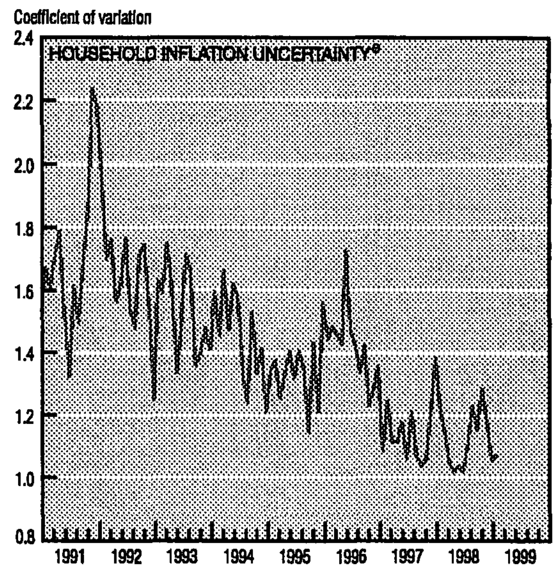
(continued on next page)

Inflation and Prices (cont.)









a. Blue Chip panel of economists.
b. Forecast data represent annualized quarterly percent change.
c. December 10 forecast.
d. Top 10 forecast minus bottom 10 forecast, divided by the consensus forecast.
e. Standard deviation of monthly responses divided by the response mean.
SOURCES: U.S. Department of Labor, Bureau of Labor Statistics; *Blue Chip Economic Indicators*, various issues; and the University of Michigan's Survey Research Center.

Although the growth trend of the CPI has moderated rather sharply in the past two years, economists are calling for a pickup in CPI increases this year and next. The consensus forecast calls for consumer price increases of 2.2% by the end of 1999 and around 2½% by the middle of 2000.

However, economists have overpredicted the rise in consumer prices a disproportionate number of times in the past six years, and their inflation projections were especially far off the mark for the past two years. In fact, economists' current inflation projections cover a wide range of opinions, with optimists seeing inflation holding around its current modest level and pessimists anticipating an inflation resurgence above 3% late next year.

The maintenance of price stability requires the central bank to provide for a stable price level *and* the expectation of its continued stability in the future. Economists' uncertainty over the price level has grown in the past year or so, presumably as they attempt to ascertain the staying power of the recently improved inflation trend.

In contrast to economists' uncertainty, households' expectations about future inflation appear to be narrowing—a positive sign for policymakers. The amplitude of variation in households' inflation expectations (relative to the mean) has decreased markedly with their inflation projections since 1996, indicating that households have increased confidence in the persistence of a moderate inflation trend.

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 23
Witness: Hack

Data Request:

Reference response to AG 1-34(d). Please generally describe the reason for the low pressure-caused interruptions. Was this a local area problem? A general area problem? Were interruptible customers located elsewhere on the system unaffected? Why have there been no more interruptions due to low system pressure since 1995. Has the problem been fixed? If so, how?

Response:

The interruptions occurred due to a transient response of Western's distribution system because of increased demand during morning peak hours. These interruptions were the result of a local area system low pressure problem and limited to this system. Over the past several years, Western's Engineering and Operations have taken steps to replace some sections of the distribution pipeline and have up-rated the system operating pressure. These changes coupled with weather conditions and load patterns have not resulted in low pressure-caused interruptions since 1995 according to our records.

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Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 24
Witness: Gary Smith

Data Request:

Reference response to AG 1-45. Please provide the referenced cost allocation guidelines in the Commission's Administrative Case No. 297.

Response:

Attached hereto, as Exhibit AG DR 2-24, are the sections from Administrative Case No. 297, dated May 29, 1987, pages 38 through 47, in which the Commission addresses Cost-of-Service study methodologies.

COST-OF-SERVICE

The record indicates a significant amount of discussion concerning cost-of-service. While the subject itself has been questioned, it has also been included in answers to questions on competition and natural gas markets. In Columbia's opinion, cost-of-service should be a first step in unraveling existing distortions between rate schedules and in the design of rates which transmit accurate price signals regarding the cost-of-service.[63] Across-the-board rate increases and average cost of gas PGAs clearly distort the communication of accurate price signals.[64]

63 Columbia response to Commission's Order dated January 17, 1986, Question No. 15c, page 16.

64 *Ibid.*, Question No. 15f, page 18.

Both TCO and Columbia Gulf support cost-based rate-making at the federal and state levels consistent with providing the flexibility necessary to compete for markets.[65] GTE supports the adoption of unbundled cost-based rates.[66] In its opinion, fully-allocated, cost-based rates with class-equalized rates of return will benefit GTE in its gas transportation program.[67] KIUC thinks the Commission, as part of this proceeding, should require LDCs to develop fully allocated, embedded cost-of-service studies showing the cost-of-service rate for each proposed class of transportation and each class of gas sales.[68] LG&E thinks cost-based rates are desirable and should be pursued unless other overriding issues exist.[69]

Southern states that since marginal rates are not fully allocated cost-based rates, some customers are charged an unfair economic rent for transportation facilities and subsidize other customers.[70] In the opinion of WKG, now is the time to move

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65 TCO and Columbia Gulf Joint response to Commission's Order dated January 17, 1986, Question No. 15c, page 8.

66 GTE response to Commission's Order dated January 17, 1986, page 1.

67 *Ibid.*, Question No. 10d, page 3.

68 KIUC response to Commission's Order dated January 17, 1986, Question No. 15g, page 15.

69 LG&E response to Commission's Order dated January 17, 1986, Question No. 15e, page 9.

70 Southern response to Commission's Order dated January 17, 1986, Question No. 14, page 17.

toward cost-based rates.[71] According to WKG, both the LDC and the Commission must recognize today's market, and move quickly to prevent or avoid further load loss to alternate fuels.[72] Further, WKG thinks the only logical way to "level the playing field" is to allow the LDC to compete on a cost-of-service sales rate and correspondingly a cost-of-service transportation rate--not one without the other.[73]

In its Draft Order the Commission concluded that since each LDC operates in a unique environment, the determination of relevant costs and costing methodology may be equally unique. The Draft Order proposed requiring cost-of-service studies by each Class A LDC to be submitted in any proposed changes to rate design in the next rate case.

At this point it is important to discuss the role of cost-of-service studies relating to rate design. Columbia stated, "Since rate design has to consider marketability and many other factors, cost of service studies just serve as more or less a guideline in any case."[74] NSA maintained that the Commission should go forward with the unbundling of services and the adoption of cost-of-

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71 WKG response to Commission's Order dated January 17, 1986, Question No. 10d, pages 7 and 8.

72 Ibid.

73 WKG response to Commission's Order dated January 17, 1986, Question No. 15c, page 20.

74 T.E., page 143.

service transportation rates.[75] In Delta's opinion ". . .in choosing from amongst alternatives in a cost of service study differences of opinion will arise as to how that study should have been done."[76]

Delta said, "[cost-of-service studies] would include recommendations on the possible de-averaging of the cost of gas and how to assign that cost by customer class. This is an area that Delta very strongly believes must be addressed."[77] Columbia[78] and LG&E[79] agree that a rate case is the appropriate means by which to examine cost-of-service studies.

The position of the AG is that, "Other factors within the Commission directions, such as rate stability and so on, are much more important than cost allocation in setting the exact rates that each customer should pay."[80] ULH&P commented, "Obviously those commenters who argue for true cost-of-service rates are the same customers who are most capable of using alternative supplies."[81]

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75 NSA response to Commission's Order dated September 30, 1986, page 2.

76 T.E., page 39.

77 Delta response to Commission's Order dated September 30, 1986, page 4.

78 T.E., page 144.

79 T.E., page 85.

80 AG response to Commission's Order dated September 30, 1986, page 14.

81 ULH&P response to Commission's Order dated September 30, 1986, page 6.

The Commission is interested in cost-of-service studies because they provide a starting point in rate design. However, they are only one factor that the Commission will consider in designing rates. The Commission believes that other principles such as adequacy, efficiency, equity, and rate stability are equally important in designing rate structures.

The principle of efficiency seeks to minimize the total resource cost associated with the supply of natural gas. Rate stability is achieved by minimizing the impact of economic dislocation due to changing rate structures. Further, equity demands an adequate structure that will enable the utility to earn a capital-attracting rate of return. The role of the Commission is to ensure that these principles are properly balanced in the rate-making process.

The Commission finds that cost-of-service studies should be completed by each Class A LDC operating in Kentucky. The Commission will consider fully allocated cost studies. The purpose of the study should be to disaggregate services and assign the appropriate cost to each service. The studies should be logically consistent and reproducible, in the sense that any interested party with some understanding of cost allocation techniques could work his way through the numbers. The studies should begin with basic accounting, financial, cost, and system planning data so that the Commission or others may use the same cost and data to prepare studies using different allocation systems. The Commission prefers that the studies be disaggregated to the greatest extent possible. Moreover, the models should be available so that alternative assumptions and allocations could be examined.

The Commission would like to more thoroughly analyze the use of weighted average cost of gas principles in rate design. The term "de-averaging" is sometimes referred to as an alternate principle of allocating the costs of gas to individual customer classes. The Commission requests that cost-of-service studies also consider how the costs of gas differ by customer class. The studies should include recommendations on the possible de-averaging of the costs of gas and how to assign that cost by customer class.

Submission and Selection of Cost-of-Service Studies

In its January 17, 1987, Order the Commission requested further testimony regarding cost-of-service studies as proposed in the Draft Order. The Commission specified timing the submission of cost-of-service studies and appropriate methodology to be used as topics for discussion.

Southern asked the Commission to reconsider and revise the parts of its Draft Order which would only allow consideration of any change in actual rates, rate design, or additional tariff offerings of Class A LDCs in a rate case upon completion of cost-of-service studies.[82] KIUC expressed concern and confusion that the language of the Draft Order would literally require consumers to await the voluntary filing of changes in rate design

82 Southern response to Commission's Order dated September 30, 1986, page 2.

and allocation at the pleasure and convenience of the LDCs.[83] Southwire[84] and Western[85] also expressed concern about the timing of cost-of-service studies.

LG&E asked the Commission to clarify that it could amend its tariff, simply to provide a minimum volume requirement or other minor conforming revisions without a full-blown rate case.[86] LG&E further stated, ". . .it is unclear why such studies should be undertaken immediately, where they are likely to become outdated before an LDC's next rate case and may result in duplicate studies which are time-consuming and expensive to prepare."[87]

Southern stated that the Draft Order should be revised to make clear that Class A LDCs complete transportation cost-of-service studies and promulgate cost-based transportation rates forthwith, and that present transportation tariffs remain in effect pending the implementation of such cost-based rates.[88] Southern was also of the opinion that the Commission had taken a step backward and was eliminating so-called downward flexibility

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83 KIUC response to Commission's Order dated September 30, 1986, pages 3 and 4.

84 Southwire response to Commission's Order dated September 30, 1986, page 4.

85 Western response to Commission's Order dated September 30, 1986, page 8.

86 LG&E response to Commission's Order dated September 30, 1986, page 4.

87 LG&E response to Commission's Order dated September 30, 1986, page 4.

88 Southern response to Commission's Order dated September 30, 1986, page 10.

in marginal transportation rates currently in effect to meet competition from alternate energy.[89]

The Commission has again reviewed the record concerning submission of cost-of-service studies and finds they should be submitted in the next rate case of each Class A LDC. As cost-of-service studies are used in determining cost allocations across all customer classes, they cannot be separated from a rate case. The decision to file a rate case is appropriately left to each utility. However, when the Commission has an issue that requires a company response it uses an investigative procedure. In the event a significant interval of time should pass before a Class A LDC files a rate case with a cost-of-service study, the Commission may require a response from that LDC. Regarding Southern's concern about flexibility, the Commission will continue to allow a flexible rate provision. Finally, the Commission confirms LG&E's commentary that conforming tariff changes, not involving rates, will be considered outside a rate case.

Selection of Cost-of-Service Methodology

In answer to the Commission's January 17, 1987, request for testimony, Delta stated, "We do not feel that a generic approach to cost-of-service studies is appropriate."[90] LG&E[91] and WKG[92] agreed with Delta.

89 Southern response to Commission's Order dated September 30, 1986, page 10.

90 T.E., page 38.

91 T.E., page 85.

92 T.E., page 110.

GTE said the Commission had not had the time or received adequate testimony about the merits or deficiencies of available cost-of-service methodologies to select one or two and impose them on all LDCs.[93] GTE suggested that the Commission consider the question of an appropriate methodology on a case-by-case basis.[94]

In the opinion of Southwire, the Commission could avoid delay by setting a timetable for the filing of a rate case based on cost of service and for a generic consideration of appropriate cost-of-service methodologies.[95] The AG stated, "The Commission should consider cost allocation studies after it has established a fair and uniform methodology or set up a range for the studies as suggested by the AG, but it should not slavishly follow them or suggest that somehow they yield a 'correct answer.'"[96]

WKG encouraged the Commission to set up a conference with each utility to discuss how the cost-of-service study should be filed and what methods should be used.[97]

The record indicates that the parties have different opinions concerning the selection of a cost-of-service methodology. The LDCs and GTE generally prefer a case-by-case decision on cost allocation methodologies. Southwire and the AG recommend a

93 T.E., page 178.

94 Ibid.

95 Southwire response to Commission's Order dated September 30, 1986, page 6.

96 AG response to Commission's Order dated September 30, 1986, pages 13 and 14.

97 T.E., page 105.

generic approach. KIUC believes the coincident demand or peak responsibility method explained in Gas Rate Fundamentals is most appropriate.[98]

The Commission finds that there are significant differences among Class A LDCs that merit case-by-case decisions on cost-of-service methodologies. The Commission is of the opinion that each Class A LDC should schedule an informal conference early in the development of its cost-of-service study. The Commission staff, as well as intervenors from the company's last rate case, should be invited to participate.

As several commenters stated, there are a variety of techniques available for cost-of-service studies. The Commission acknowledges that there is not a single acceptable method to prepare such a study. Each LDC is encouraged to choose the method it finds appropriate.

The Commission is concerned about cost-of-service methodologies that place all the emphasis on maximum design day as a way to allocate costs. This method may result in an inappropriate shift of costs to the residential customer class. For this reason, cost-of-service methodologies should give some consideration to volume of use.

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98 T.E., page 197.

25

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 25
Witness: Hack

Data Request:

Reference response to AG 1-139. The load data requested in parts (a), (b), (c), and (e) was customer class load data, not system data. Please provide the originally requested Item 139 data, by customer class.

Response:

System delivery data is the only data available for any particular day. The residential, commercial and industrial classes of customers with the exception of a small number of large commercial and industrial customers do not have electronic flow meters that would provide this daily information. The Company reads meters for its customers on a monthly cycle basis. The only means of obtaining a daily usage for metered customers without electronic flow measurement would be to read each customer's meter index at the beginning of the gas day and again at the end of the gas day. Therefore, the information requested in AG 1-139 for parts (a), (b), (c) and (e) is not available.

26

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Data Request:

Using the format of Schedule B, provided in the response to KPSC 1-69(b), please provide the actual monthly level of employees during the base period for Western. For each month indicate the number of authorized positions.

Response:

Please see attached Schedule (24 pages).

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	October 1998 Positions Authorized	October 1998 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Executive Vice President	0	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	15	9
Operations Assistant	21	21
Operations Manager	5	5
Operations Specialist	13	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	4
Service Specialist	10	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	55	51

Western Kentucky Gas Company
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Witness: Betty L. Adams

Job Title	October 1998 Positions Authorized	October 1998 Employee Complement
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1
VP Marketing	1	1
VP Rates & Regulatory Affairs	0	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
WKG Totals	282	269

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	November 1998 Positions Authorized	Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Executive Vice President	0	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	15	9
Operations Assistant	21	21
Operations Manager	5	5
Operations Specialist	13	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	4
Service Specialist	10	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	55	51
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	November 1998 Positions Authorized	November 1998 Employee Complement
VP Human Resources	1	1
VP Marketing	1	1
VP Rates & Regulatory Affairs	0	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	269

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	December 1998 Positions Authorized	December 1998 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Executive Vice President	0	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	15	9
Operations Assistant	21	21
Operations Manager	5	5
Operations Specialist	13	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	4
Service Specialist	10	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	55	51
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	December 1998 Positions Authorized	Employee Complement
VP Human Resources	1	1
VP Marketing	1	1
VP Rates & Regulatory Affairs	0	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	269

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	January 1999 Positions Authorized	Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	15	9
Operations Assistant	21	21
Operations Manager	5	5
Operations Specialist	13	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	4
Service Specialist	10	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	55	50
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	January 1999 Positions Authorized	January 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	0	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	267

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	February 1999 Positions Authorized	February 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	2
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	15	9
Operations Assistant	21	21
Operations Manager	5	5
Operations Specialist	13	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	10	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	55	50
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

VP Marketing	1	1
VP Rates & Regulatory Affairs	0	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	267

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	March 1999 Positions Authorized	March 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	2
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	1
Sr. Service Technician	58	52
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	March 1999 Positions Authorized	March 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	262

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	April 1999 Positions Authorized	April 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	13
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	2
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	14
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	11
Service Technician	9	11
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	20
Sr. Engineer	2	1
Sr. Service Technician	58	50
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	April 1999 Positions Authorized	April 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	265

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	May 1999 Positions Authorized	May 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	2
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	0
Sr. Service Technician	58	52
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	May 1999 Positions Authorized	May 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	261

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	June 1999 Positions Authorized	June 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	0
Sr. Service Technician	58	52
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	June 1999 Positions Authorized	June 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	260

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	July 1999 Positions Authorized	July 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	23
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	0
Sr. Service Technician	58	52
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	July 1999 Positions Authorized	July 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	260

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	August 1999 Positions Authorized	August 1999 Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	22
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	0
Sr. Service Technician	58	52
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	August 1999 Positions Authorized	August 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	259

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	September 1999 Positions Authorized	Employee Complement
Computer Mapping Techinician	3	3
Contruction Operator	13	11
Corrision Control Coordinator	1	1
Corrison Control Technician	6	6
Crew Foreman	24	22
Emp. Development & Safety Coordinator	2	2
Engineering Technician	5	5
Executive Assistant	1	1
Field Operator	8	8
Field Support Analyst	2	2
Financial Analyst	1	1
Laborer	2	2
Large Volume Sales Engineer	1	1
Manager Engineering Services	2	2
Manager Information Services	1	1
Manager Public Affairs	1	1
Manager Sales	2	1
Measurement Specialist	2	2
Measurement Supervisor	1	1
Meter Reader	10	8
Operations Assistant	21	20
Operations Manager	5	5
Operations Specialist	12	12
Operations Supervisor	15	13
President	1	1
Sales Representative I	2	2
Sales Representative II	4	3
Service Specialist	12	10
Service Technician	9	9
Sr. Administrative Assistant	4	4
Sr. Construction Operator	23	21
Sr. Engineer	2	0
Sr. Service Technician	58	51
Storage Foreman	2	2
Storage Technician	2	2
Town Operator	9	9
VP & Controller	1	1
VP Eastern Region	1	1
VP Human Resources	1	1

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 26
Witness: Betty L. Adams

Job Title	September 1999 Positions Authorized	September 1999 Employee Complement
VP Marketing	1	1
VP Rates & Regulatory Affairs	1	1
VP Technical Services	1	1
VP Western Region	1	1
Warehouse Coordinator	1	1
Warehouse Technician	5	5
Total WKG	282	258

Western Kentucky Gas Company
Case No. 99-070
Attorney General Initial Data Request Dated September 20, 1999
DR Item 27
Witness: Betty Adams

Data Request:

Please provide the actual monthly level of employees during the base period for Shared Services. For each month indicate the number of authorized positions.

Response:

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Actual	389	386	401	398	400	407	412	421	414	428	418
Contractors	56	59	56	49	54	56	60	57	45	42	26
Authorized	468	488	492	481	506	506	506	506	506	506	506

28

Western Kentucky Gas Company
Case No. 99-070
Attorney General Supplemental Data Request Dated September 20, 1999
DR Item 28
Witness: Betty Adams

Data Request:

With reference to the response to AG 1-241, both the referenced testimony and Schedule C-2.2 appear to indicate that the base year data and the forecasted period data are presented on the NARUC account basis. If both periods are presented on the same basis, please explain why the account fluctuations noted in Items (h) through (t) can be the result of converting from O&M budget cost elements to NARUC accounts. Given that the accounts are presented on the same basis, wouldn't the differences between the periods result from actual changes in activities? Please explain fully.

Response:

The reason for the fluctuations can be found in the method which was used to convert the O&M budget from a cost element basis to NARUC accounts. The entire Fiscal Year 1999 and Forecasted Test Year budgets were loaded into an Access database which contained Fiscal Year 1998 actual data. This actual data was broken down by cost center, cost element, and NARUC account. The percentage that each NARUC account was of each cost center/ cost element combination was applied to the same cost center/cost element combination found in the two budgets. This means that the data in both budgets was allocated on the same basis. However, once this conversion had taken place, the actual data for the first 6 months of Fiscal Year 1999 was applied in place of the budget data for the same time periods. This actual data may or may not have the same cost center/cost element/NARUC account relationships as the converted budget data. Therefore, this new "combination" Fiscal Year 1999 (test year) has different total amounts for the NARUC accounts than the Forecasted Test Year budget. Even though these NARUC accounts might fluctuate between years, it is imperative to remember that Atmos budgets, not at the NARUC account level, but at the cost element level and that the budgets are reviewed by each responsible area for consistency and reliability. The Access model has captured the total budgeted dollars and these reconcile to the approved budgets and financial statements.

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PUBLIC SERVICE
COMMISSION

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 1
Witness: Smith

Data Request:

Provide a listing of all receipt points, including those with local producers of natural gas and all interstate pipelines, under all currently effective Rate T-2, T-3 and T-4 service contracts whereby the terms and conditions of Rate T-5 would not apply to such receipt point for any reason. Please provide this listing by customer name, contract number, and receipt point.

Response:

Westerns Service Agreement with each transportation customer under tariff Rates T-2, T-3 and T-4 designates the point to which supplies must be delivered to the Company. This point represents their traditional, or "primary", receipt point (reference DR Item 8); any point of receipt for the Customer other than the noted point would be an "alternate" receipt point under Westerns proposed tariff service. Presently, these tariff T-2, T-3 and T-4 customers have no alternative point for Westerns receipt of their supplies. This is also true of Westerns special contract transportation services, approved by the Commission - other than for one special contract carriage customer afforded access to two receipt points. With this lone exception, for all of Westerns transportation customers, the receipt point is a single interconnect point - with either Texas Gas Transmission or Tennessee Gas Pipeline.

Exhibit WBIS #1, DR 1 summarizes the receipt points specified in Westerns Service Agreement under currently effective tariff Rate T-2, T-3 and T-4 services, as well as special contract transportation services. In accordance with discussions between Western and WBI-Southern subsequent to our receipt of this data request, this Exhibit excludes the identification of Westerns customers and the associated contract number, due to the confidential and proprietary nature of this information.

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
<u>DR Item 1</u>

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	8	FOR THE DANVILLE SALES STATION IN BOYLE COUNTY, KENTUCKY, AT MAIN LINE	TN #20014
2		VALVE 100 - 1, PLUS 3.0 MILES	
3			
4	4	FOR THE HARRODSBURG SALES STATION IN BOYLE COUNTY, KENTUCKY, AT MAIN	TN #20028
5		LINE VALVE 100 - 1	
6			
7	5	FOR THE LEBANON SALES STATION IN MARION COUNTY, KENTUCKY, AT MAIN LINE	TN #20030
8		VALVE 97 - 1, PLUS 0.02 MILES	
9			
10	1	A METERING STATION LOCATED IN LYON COUNTY, KENTUCKY, AT THE	TG #1882
11		INTERCONNECTION BETWEEN SELLER'S AND BUYER'S PIPELINE FACILITIES AT	
12		LONGITUDE 88 DEGREES, 2 MINUTES, 33 SECONDS, LATITUDE 37 DEGREES, 10 MINUTES,	
13		24 SECONDS, APPROXIMATELY 3.5 MILES SOUTH OF FREDONIA, KENTUCKY	
14			
15	9	A METERING STATION LOCATED IN MARSHALL COUNTY, KENTUCKY, AT LONGITUDE	TG # 1884
16		88 DEGREES, 18 MINUTES, 15 SECONDS, LATITUDE 37 DEGREES, 1 MINUTE,	
17		45 SECONDS, APPROXIMATELY 0.5 MILES WEST OF GILBERTSVILLE, KENTUCKY	
18			
19	1	A METERING STATION LOCATED IN LIVINGSTON COUNTY, KENTUCKY, AT LONGITUDE	TG #1887
20		88 DEGREES, 17 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 3 MINUTES,	
21		15 SECONDS, APPROXIMATELY 3.5 MILES NORTHWEST OF GRAND RIVERS, KENTUCKY	
22			
23	8	A METERING STATION LOCATED IN GRAVES COUNTY, KENTUCKY, AT LONGITUDE	TG #1889
24		88 DEGREES, 36 MINUTES, 15 SECONDS, LATITUDE 36 DEGREES, 44 MINUTES,	
25		0 SECONDS, APPROXIMATELY 2.0 MILES EAST OF MAYFIELD, KENTUCKY	

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
DR Item 1

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	7	A METERING STATION LOCATED IN MARSHALL COUNTY, KENTUCKY, AT LONGITUDE	TG #1891
2		88 DEGREES, 24 MINUTES, 15 SECONDS, LATITUDE 36 DEGREES, 56 MINUTES,	
3		30 SECONDS, APPROXIMATELY 6.0 MILES NORTHWEST OF BENTON, KENTUCKY	
4			
5	1	A METERING STATION LOCATED IN LOGAN COUNTY, KENTUCKY, AT LONGITUDE	TG #1896
6		86 DEGREES, 46 MINUTES, 30 SECONDS, LATITUDE 36 DEGREES, 44 MINUTES,	
7		45 SECONDS, APPROXIMATELY 1.5 MILES NORTHEAST OF SCHOCHOH, KENTUCKY	
8			
9	1	A METERING STATION LOCATED IN LOGAN COUNTY, KENTUCKY, AT LONGITUDE	TG #1898
10		86 DEGREES, 42 MINUTES, 30 SECONDS, LATITUDE 36 DEGREES, 52 MINUTES,	
11		30 SECONDS, LOCATED IN AUBURN, KENTUCKY	
12			
13	12	A METERING STATION LOCATED IN WARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1900
14		86 DEGREES, 29 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 1 MINUTE,	
15		30 SECONDS, APPROXIMATELY 1.5 MILES NORTH OF BOWLING GREEN, KENTUCKY	
16			
17	8	A METERING STATION LOCATED IN WARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1901
18		86 DEGREES, 31 MINUTES, 0 SECONDS, LATITUDE 36 DEGREES, 57 MINUTES,	
19		30 SECONDS, APPROXIMATELY 1.5 MILES WEST OF BOWLING GREEN, KENTUCKY	
20			
21	1	A METERING STATION LOCATED IN LOGAN COUNTY, KENTUCKY, AT LONGITUDE	TG #1903
22		87 DEGREES, 0 MINUTES, 0 SECONDS, LATITUDE 36 DEGREES, 51 MINUTES,	
23		15 SECONDS, APPROXIMATELY 5.5 MILES WEST OF RUSSELLVILLE, KENTUCKY	

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
DR Item 1

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	1	A METERING STATION LOCATED IN BARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1905
2		85 DEGREES, 57 MINUTES, 30 SECONDS, LATITUDE 37 DEGREES, 7 MINUTES,	
3		30 SECONDS, LOCATED IN CAVE CITY, KENTUCKY	
4			
5	2	A METERING STATION LOCATED IN BARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1914
6		85 DEGREES, 56 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 0 MINUTES,	
7		45 SECONDS, APPROXIMATELY 0.5 MILES WEST OF GLASGOW, KENTUCKY	
8			
9	3	A METERING STATION LOCATED IN TODD COUNTY, KENTUCKY, AT LONGITUDE	TG #1915
10		87 DEGREES, 10 MINUTES, 0 SECONDS, LATITUDE 36 DEGREES, 53 MINUTES,	
11		45 SECONDS, APPROXIMATELY 5.0 MILES NORTH OF ELKTON, KENTUCKY	
12			
13	3	A METERING STATION LOCATED IN WARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1916
14		86 DEGREES, 21 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 2 MINUTES,	
15		15 SECONDS, APPROXIMATELY 4.0 MILES NORTHEAST OF BOWLING GREEN, KENTUCKY	
16			
17	2	A METERING STATION LOCATED IN SIMPSON COUNTY, KENTUCKY, AT LONGITUDE	TG #1917
18		86 DEGREES, 35 MINUTES, 30 SECONDS, LATITUDE 36 DEGREES, 43 MINUTES,	
19		0 SECONDS, APPROXIMATELY 0.3 MILES SOUTH OF FRANKLIN, KENTUCKY	
20			
21	2	A METERING STATION LOCATED IN WARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1918
22		86 DEGREES, 32 MINUTES, 30 SECONDS, LATITUDE 36 DEGREES, 50 MINUTES,	
23		0 SECONDS, APPROXIMATELY 0.5 MILES SOUTHWEST OF WOODBURN, KENTUCKY	

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
DR Item 1

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	2	A METERING STATION LOCATED IN BARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1920
2		85 DEGREES, 54 MINUTES, 15 SECONDS, LATITUDE 37 DEGREES, 1 MINUTE,	
3		0 SECONDS, APPROXIMATELY 0.5 MILES EAST OF GLASGOW, KENTUCKY	
4			
5	3	A METERING STATION LOCATED IN BARREN COUNTY, KENTUCKY, AT LONGITUDE	TG #1921
6		85 DEGREES, 55 MINUTES, 15 SECONDS, LATITUDE 37 DEGREES, 0 MINUTES,	
7		0 SECONDS, APPROXIMATELY 0.1 MILES SOUTH OF GLASGOW, KENTUCKY	
8			
9	2	A METERING STATION LOCATED IN MUHLENBURG COUNTY, KENTUCKY, AT LONGITUDE	TG #1922
10		87 DEGREES, 11 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 12 MINUTES,	
11		30 SECONDS, APPROXIMATELY 0.3 MILES WEST OF GREENVILLE, KENTUCKY	
12			
13	17	A METERING STATION LOCATED IN DAVIESS COUNTY, KENTUCKY, AT LONGITUDE	TG #1924
14		86 DEGREES, 57 MINUTES, 30 SECONDS, LATITUDE 37 DEGREES, 40 MINUTES,	
15		45 SECONDS, APPROXIMATELY 2.0 MILES SOUTHEAST OF HABIT, KENTUCKY	
16			
17	1	A METERING STATION LOCATED IN HANCOCK COUNTY, KENTUCKY, AT LONGITUDE	TG #1926
18		86 DEGREES, 45 MINUTES, 45 SECONDS, LATITUDE 37 DEGREES, 54 MINUTES,	
19		45 SECONDS, APPROXIMATELY 0.3 MILES WEST OF HAWESVILLE, KENTUCKY	
20			
21	1	A METERING STATION LOCATED IN DAVIESS COUNTY, KENTUCKY, AT LONGITUDE	TG #1927
22		87 DEGREES, 1 MINUTE, 0 SECONDS, LATITUDE 37 DEGREES, 39 MINUTES,	
23		30 SECONDS, APPROXIMATELY 1.5 MILES SOUTH OF MASONVILLE, KENTUCKY	

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
DR Item 1

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	3	A METERING STATION LOCATED IN HANCOCK COUNTY, KENTUCKY, AT LONGITUDE	TG #1928
2		86 DEGREES, 45 MINUTES, 45 SECONDS, LATITUDE 37 DEGREES, 54 MINUTES,	
3		45 SECONDS, APPROXIMATELY 0.1 MILES WEST OF HAWESVILLE, KENTUCKY	
4			
5	1	A METERING STATION LOCATED IN HANCOCK COUNTY, KENTUCKY, AT LONGITUDE	TG #1929
6		86 DEGREES, 46 MINUTES, 45 SECONDS, LATITUDE 37 DEGREES, 54 MINUTES,	
7		45 SECONDS, APPROXIMATELY 1.0 MILES SOUTH OF HAWESVILLE, KENTUCKY	
8			
9	1	A METERING STATION LOCATED IN HART COUNTY, KENTUCKY, AT LONGITUDE	TG #1934
10		85 DEGREES, 54 MINUTES, 45 SECONDS, LATITUDE 37 DEGREES, 11 MINUTES,	
11		0 SECONDS, APPROXIMATELY 0.1 MILES WEST OF HORSE CAVE, KENTUCKY	
12			
13	8	A METERING STATION LOCATED IN HOPKINS COUNTY, KENTUCKY, AT LONGITUDE	TG #1939
14		87 DEGREES, 32 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 19MINUTES,	
15		0 SECONDS, APPROXIMATELY 0.5 MILES SOUTHWEST OF MADISONVILLE, KENTUCKY	
16			
17	2	A METERING STATION LOCATED IN CALDWELL COUNTY, KENTUCKY, AT LONGITUDE	TG #1940
18		88 DEGREES, 2 MINUTES, 0 SECONDS, LATITUDE 37 DEGREES, 11 MINUTES,	
19		15 SECONDS, APPROXIMATELY 2.0 MILES SOUTH OF FREDONIA, KENTUCKY	
20			
21	2	A METERING STATION LOCATED IN DAVIESS COUNTY, KENTUCKY, AT LONGITUDE	TG #1942
22		87 DEGREES, 11 MINUTES, 45 SECONDS, LATITUDE 37 DEGREES, 40 MINUTES,	
23		45 SECONDS, APPROXIMATELY 1.0 MILES NORTH OF MOSELEYVILLE, KENTUCKY	

WESTERN KENTUCKY GAS COMPANY
CASE NO. 99-070
WBI SOUTHERN, INC. DATA REQUEST DATED SEPTEMBER 14, 1999
DR Item 1

Line No.	WKG Transp. Customers	PIPELINE RECEIPT POINT DESCRIPTION	Pipeline Meter Number {1}
	(a)	(b)	(c)
1	15	A METERING STATION LOCATED IN HOPKINS COUNTY, KENTUCKY, AT LONGITUDE	TG #1948
2		87 DEGREES, 28 MINUTES, 30 SECONDS, LATITUDE 37 DEGREES, 11 MINUTES,	
3		30 SECONDS, APPROXIMATELY 1.5 MILES WEST OF NORTONVILLE, KENTUCKY	
4			
5	1	A METERING STATION LOCATED IN HENDERSON COUNTY, KENTUCKY, AT LONGITUDE	TG #1955
6		87 DEGREES, 32 MINUTES, 30 SECONDS, LATITUDE 37 DEGREES, 40 MINUTES,	
7		15 SECONDS, APPROXIMATELY 0.1 MILES WEST OF ROBARDS, KENTUCKY	
8			
9	4	A METERING STATION LOCATED IN LOGAN COUNTY, KENTUCKY, AT LONGITUDE	TG #1959
10		86 DEGREES, 54 MINUTES, 0 SECONDS, LATITUDE 36 DEGREES, 50 MINUTES,	
11		0 SECONDS, APPROXIMATELY 0.1 MILES EAST OF RUSSELLVILLE, KENTUCKY	
12			
13	16	A METERING STATION LOCATED IN JEFFERSON COUNTY, KENTUCKY, AT LONGITUDE	TG #1984
14		85 DEGREES, 29 MINUTES, 15 SECONDS, LATITUDE 38 DEGREES, 16 MINUTES,	
15		15 SECONDS, APPROXIMATELY 2.0 MILES EAST OF ANCHORAGE, KENTUCKY	
16			
17	1	A METERING STATION LOCATED IN HENDERSON COUNTY, KENTUCKY, AT LONGITUDE	TG #1986
18		87 DEGREES, 31 MINUTES, 18 SECONDS, LATITUDE 37 DEGREES, 39 MINUTES,	
19		18 SECONDS, ON THE SLAUGHTERS-EVANSVILLE 10-INCH LINE	
20			
21	1	ELAS / WESTERN KENTUCKY	MW # 0207068-01
22			
23	NOTE {1} -	TN designates Tennessee Gas Pipeline, TG designates Texas Gas Transmission, and MW designates Midwestern Pipeline.	

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 2
Witness: Smith

Data Request:

Provide a listing of all locations, including those with local producers of natural gas and all interstate pipelines, where alternate points under currently effective Rate T-2, T-3, and T-4 service contracts would be required to follow the terms and conditions of Rate T-5. Please provide this listing by customer name, contract number, and location.

Response:

There are no alternate points of receipt specified in Westerns Service Agreements with customers under tariff Rates T-2, T-3 and T-4 services (reference DR Item 8 for further information). This is also true of Westerns special contract transportation services, approved by the Commission - other than for one special contract carriage customer afforded access to two receipt points. Westerns proposed T-5 would not apply to these existing points of receipt, as designated under each customer service agreement.

Please refer to the Exhibit provided as an attachment to DR Item 1 of this WBI Southern, Inc. Data Request, Exhibit WBIS #1, DR 1. This Exhibit summarizes the receipt points specified in Westerns Service Agreement under currently effective tariff Rate T-2, T-3 and T-4 services, as well as special contract transportation services. In accordance with discussions between Western and WBI-Southern subsequent to our receipt of this data request, this Exhibit excludes the identification of Westerns customers and the associated contract number, due to the confidential and proprietary nature of this information.

Any point of receipt for the T-2, T-3 and T-4 transportation customer other than their currently noted receipt point would be an "alternate" receipt point, subject to the terms and conditions of Westerns proposed Rate T-5 service.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 3
Witness: Smith

Data Request:

Provide a listing of all local producers, interstate pipelines, Western Kentucky customers and other parties with whom Western Kentucky has entered any agreement, or has discussed any agreement, whereby Rate T-5 would not apply to such producer, pipeline or other customer in the manner provided in the Application. This response should include a description of the manner in which Rate T-5 would apply to such persons and Western Kentucky's justification for modifying the application of Rate T-5 to such persons.

Response:

As stated in the Company's response to DR Items 1 and 2 of this WBI-Southern, Inc. Data Request, the terms of the proposed Rate T-5 service would not apply to the receipt points designated in Westerns current service agreements with transportation customers. One special contract customer has two receipt points, all other tariff and special contracts designate a single point of receipt for each customer. Westerns proposed Rate T-5 will afford the potential option for the Customer to utilize alternative receipt points - supplemental to the traditional receipt point designated under their current transportation service agreement.

Western has not entered into any agreement waiving the provisions of the proposed Rate T-5 tariff for any future transactions. Western has received one request for a waiver of the Rate T-5 provisions, from Innovative Gas Services for potential future receipts at the East Diamond Storage Field (see DR Item 5 of this Data Request). Western did not grant the requested waiver.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 4
Witness: Smith

Data Request:

Provide all projections, studies, documents and analyses used by Western Kentucky in the preparation of Rate T-5. In addition, include any correspondence from customers requesting that Western Kentucky provide such a service and any internal studies or correspondence shown the financial and operational effects on Western Kentucky as a result of it providing such a service.

Response:

There are no workpapers, studies or cost/revenue analyses which were utilized in Western's development of the proposed tariff, other than the testimony of Gary L. Smith, Volume 2 of 10, Tab 11 of the Application, at page 31, line 28 through page 33, line 10, Exhibit GLS-7 of Mr. Smith's testimony, column (j), line 20, whereby volumes of 100,000 Mcf per year under Rate T-5 service was projected, and in the Company's proposed tariff, at First Revised Sheets 49 and 50 (Volume 1 of 10, Tab 6 of the Application).

Although Western has received verbal inquiries from transportation customers and their agents about the possibility of using alternate points of receipt for their supplies into the Company's system, we are unaware of any written correspondence to that effect.

Please also refer to the Company's response to the KPSC Data Request Dated July 16, 1999 concerning Western's considerations in establishing the proposed charge of $0.10 per Mcf under the proposed T-5 service. A copy of the referenced response is provided as an attachment to DR Item 7 of this Data Request as Exhibit WBIS #1 - Item 7.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 5
Witness: Smith

Data Request:

WBI Southern has been informed that in the event eligible Western Kentucky customers elect to utilize the proposed interconnect between Western Kentucky and WBI Southern at the East Diamond Storage Field as a designated point of receipt, such service would be subject to the terms and conditions of Rate T-5. Explain why such interconnect does not currently qualify as Western Kentucky's interconnection with the pipeline as defined in Section 2(a) of Rate T-5?

Response:

Section 2(a) of the proposed Rate T-5 tariff is referring to the receipt point, as specified in current transportation and carriage service agreements, through which Western has physically received the supply for redelivery to the plant site. The intent of Westerns proposed Rate T-5 tariff is to establish a framework under which transportation customers could utilize an optional, alternate point of receipt into Westerns system.

The interconnect between WBI Southern and Western at the East Diamond Storage Field referenced above, is not currently in place. This interconnect does not represent the traditional point of supply receipt into Western's system for any of the Company's current transportation customers (reference DR Item 8 of this Data Request for additional information).

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 6
Witness: Smith

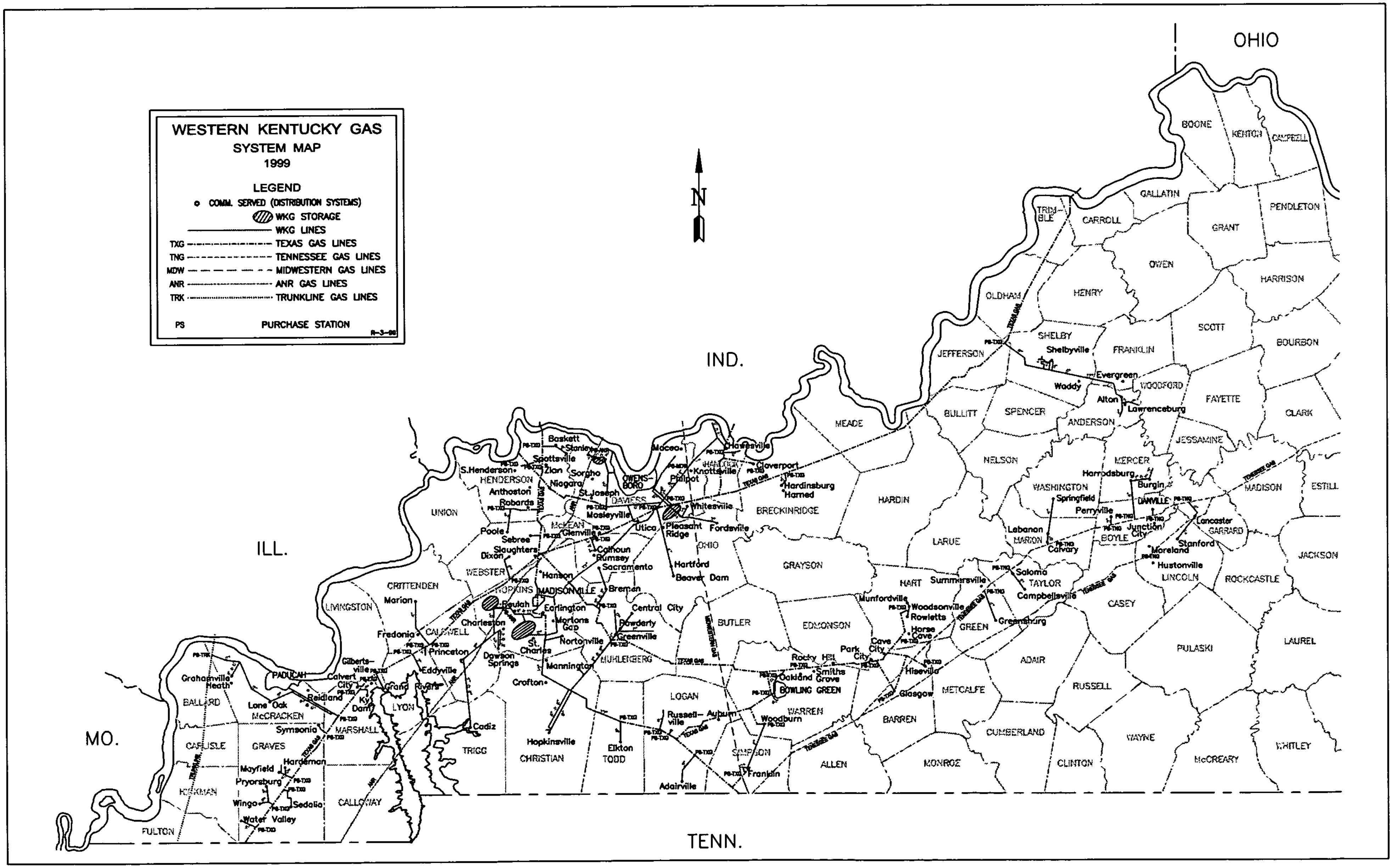
Data Request:

Please provide all engineering and operational studies, including system flow diagrams, utilized by Western Kentucky to determine the location of all receipt points relative to its customers' premises and those points that would be considered "upstream" to specific customer service areas.

Response:

With respect to the upstream point of receipt designated under Westerns service agreement with its T-2, T-3 and T-4 transportation customers, no engineering or operational studies are necessary in that determination.

A map of Westerns system, showing the major interconnects with interstate pipelines, is attached hereto.


WESTERN KENTUCKY GAS
SYSTEM MAP
1999
LEGEND
COMM. SERVED (DISTRIBUTION SYSTEMS)
WKG STORAGE
WKG LINES
TXG TEXAS GAS LINES
TNG TENNESSEE GAS LINES
MDW MIDWESTERN GAS LINES
ANR ANR GAS LINES
TRK TRUNKLINE GAS LINES
PS PURCHASE STATION
OHIO
IND.
ILL.
MO.
TENN.

7

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 7
Witness: Smith

Data Request:

Explain Western Kentucky's justification for imposing an additional charge for an alternate receipt point? Are costs allocated to such Rate T-5? If so, why? If not, why not?

Response:

Please refer to the Company's response to the KPSC Data Request Dated July 16, 1999. A copy of this response is attached hereto as Exhibit WBIS #1 - Item 7.

EXHIBIT
WBIS#1-Item 7

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.

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Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 8
Witness: Smith

Data Request:

Explain from an operational standpoint, why it is necessary to implement Rate T-5?

Response:

Currently, Western's tariff transportation customers do not have the option of utilizing an alternative receipt point. To understand the operational complexity of Western's offering of this new option, it is important that certain fundamental aspects of the Company's system be recognized.

Western's distribution systems were originally established utilizing pipeline interconnects with either Texas Gas Transmission or Tennessee Gas Pipeline as the source of gas supply. Western's pipeline systems were extended, and in a small number of cases, integrated with one another. Company-owned storage facilities were developed and were integrated into Western's operational assurance of reliable merchant service to its firm sales customers. Distribution system operations were based upon supplies entering Western's system at the traditional interstate pipeline interconnects. It is at these interconnects where most of the gas flow into Western's system occurs and where primary pressure control and flow monitoring is performed.

In the mid-1980's, Western began allowing large consumers (industries) to transport their own supplies through the Company's distribution system. Utilizing the balancing attributes of Western's service from Texas Gas and Tennessee Gas, Western could offer certain balancing benefits to its transportation customers. Although Western's transportation services have evolved and expanded, tariff transportation customers can only utilize the interstate pipeline interconnect from which their specific upstream system was traditionally supplied.

In recent years, Western has added interconnects with other interstate pipelines - ANR, Trunkline and Midwestern. These additional receipt points, utilized for Western's purchase of a portion of its core market supplies, feed into isolated sections of the Company's distribution system.

Western proposed the Rate T-5 tariff to establish a framework under which transportation and carriage service customers, in some cases, could be afforded access to these new interconnects or other alternative supply receipt points into Western's system.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 8
Witness: Smith

As stated in the testimony of Gary Smith, Volume 2 of 10 of the Company's Application, Tab 11, at page 32, lines 17 through 25, several operational conditions limit the availability of the Rate T-5 service. As indicated above, some transportation customers are physically served through an isolated distribution system, without potential access to alternate receipt points. Other customers are served through an integrated distribution system, which could afford conditional access to an alternative receipt point into Western's system. In the latter case, physical constraints at the interconnect or through the alternative distribution system route, could limit or preclude the transaction.

With respect to these limitations, Western believes it is important to establish a framework through which the alternate receipt point service is afforded - to assure that such access is provided in a non-discriminatory manner. Several related operational and administrative processes must also be established, to assure that the customers nominations are handled in an orderly fashion, and, importantly, to ensure that these transactions do not detrimentally impact the Company's receipts for core market sales customers. Many of these administrative details will not be fully resolved until the Commission's decision regarding this proposed tariff is rendered. Subsequent to the Order establishing the framework under the T-5 tariff, Western will communicate to Customers the processes for submittal/ handling of T-5 requests and the associated procedural responsibilities, such as supply balancing and nominations.

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Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 9
Witness: Smith

Data Request:

Explain how Western Kentucky determined that a $0.10 Mcf rate is appropriate to Rate T-5? Please provide all workpapers, studies, cost/revenue projections and analyses relied upon in such determination.

Response:

Please refer to the Company's response to the KPSC Data Request Dated July 16, 1999. A copy of the referenced response is provided as an attachment to DR Item 7 of this Data Request as Exhibit WBIS #1 - Item 7.

There are no workpapers, studies or cost/revenue analyses which were utilized in Western's development of the proposed tariff, other than the testimony of Gary L. Smith, Volume 2 of 10, Tab 11 of the Application, at page 31, line 28 through page 33, line 10, Exhibit GLS-7 of Mr. Smith's testimony, column (j), line 20, whereby volumes of 100,000 Mcf per year under Rate T-5 service was projected, and in the Company's proposed tariff, at First Revised Sheets 49 and 50 (Volume 1 of 10, Tab 6 of the Application).

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Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 10
Witness: Smith

Data Request:

Explain why volumes delivered by Western Kentucky under the Alternate Receipt Point Service may be subject to imbalance restrictions in addition to those specified in the Rate T-2, T-3, or T-4 tariffs?

Response:

As noted in the Company's response to DR Item 1 of this WBI-Southern data request, with the exception of one special contract customer, each of Western's transportation customers has a single designated receipt point, an interconnect point with either Texas Gas Transmission or Tennessee Gas Pipeline.

With both of these interstate pipelines, there are factors that contribute to Western's capability to provide a degree of flexibility regarding the Customer's supply imbalances. For example, with the level of customer transportation and system supply purchases through both pipelines, an individual customer's imbalance may be neutralized by an offsetting imbalance for another transporting customer. Also, Western may carry net daily receipt point imbalances during certain periods, utilizing no-notice or storage balancing services under our contracts with these interstate pipelines.

Such balancing flexibility may or may not be associated with a transportation customers receipts at an alternative receipt point.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 11
Witness: Smith

Data Request:

Explain why Banking or Parking allowances for volumes delivered under the Alternate Receipt Point Service under Rate T-5 may be limited or restricted altogether, at Western Kentucky's soles judgment?

Response:

As noted in the Company's response to DR Item 1 of this WBI-Southern data request, with the exception of one special contract customer, each of Western's transportation customers has a single designated receipt point, an interconnect point with either Texas Gas Transmission or Tennessee Gas Pipeline.

Western's current T-2 tariff allows a customer to bank up to 10% of their monthly nominated supply for use in the next month, without subjecting the over-nominated supply volume to the Company's "cash-out" provisions. Similarly, by election of the customer, Western's current T-3 and T-4 tariffs allow a customer to park up to 10% of their monthly nominated supply for use in the next month, for a fee of $0.10 per Mcf parked, without subjecting the over-nominated supply volume to the Company's "cash-out" provisions.

Western can accommodate these monthly balancing services due to the nature of our operational parameters with Texas Gas and Tennessee Gas Pipeline. For example, with the level of customer transportation and system supply purchases through both pipelines, an individual customer's imbalance may be neutralized by an offsetting imbalance for another transporting customer. Also, Western may carry net daily receipt point imbalances during certain periods, utilizing no-notice or storage balancing services under our contracts with these interstate pipelines.

Such monthly balancing flexibility may or may not be associated with a transportation customers receipts at an alternative receipt point.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 12
Witness: Smith

Data Request:

Section 2(c) of Rate T-5 allows Western Kentucky to determine, in its sole judgment, whether access will be allowed to any alternate receipt point. Provide all policies, processes, and procedures Western Kentucky has developed to prevent the use of such authority in a discriminatory manner?

Response:

Section 2 (c) of the proposed Rate T-5 tariff states that the Company shall determine the portions of its system to which the option of access may be granted to a specific alternate receipt point. Among the conditions that would prohibit access to a specific alternate receipt point for a given customer are:

- the alternate point must be physically accessible via the Company's existing distribution system upstream of the delivery point to the Customer's facilities (Reference Section 2(b) of the proposed Rate T-5 tariff, and see DR Item 8 of this request for additional information);
- if the preceding condition is met, the Company shall determine whether capacity for the requested service is available through those existing distribution facilities (Reference Section 2(e) of the proposed Rate T-5 tariff); and
- if the preceding two conditions are met, the Company would place any additional limitations, as necessary, to ensure that there is no detrimental impact caused by the transaction upon the Company's receipts of system supply for core market sales customers (Reference Section 2(f) of the proposed Rate T-5 tariff).

Upon the approval by the Commission of this new, optional service for Western's transportation customers, the Company will prepare and communicate to its Customers the processes for submittal/handling of T-5 requests and the associated procedural responsibilities.

13

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 13
Witness: Smith

Data Request:

Explain how the proposed Rate T-5 service will not discriminate against production and storage operators with properties located entirely within the Commonwealth of Kentucky in the form of restricted access and incremental service costs?

Response:

Currently the only available means for deliveries of local production or storage (no such storage supplies have been delivered to Western, except for a Customer-owned storage field) into Western's system is for the Company to purchase the volumes for system supply for core market sales customers. Rate T-5 will create a new and separate market opportunity heretofore not available either to these potential suppliers or to Westerns transportation customers.

Please refer to the Company's response to DR Item 12 of this Data Request concerning the necessary restrictions on customer access to specific alternate receipt points and to DR Items 7 and 9 of this Data Request concerning the Company's proposed $0.10/Mcf charge for alternate receipt point volumes.

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 14
Witness: Smith

Data Request:

Explain why charging an additional $0.10 per Mcf for new supply sources of gas on Western Kentucky's system would not be discriminatory to such sources?

Response:

Currently the only available means for deliveries of local production or storage into Western's system (no such storage supplies have been delivered to Western, except for a Customer-owned storage field) is for the Company to purchase the volumes for system supply for core market sales customers. Rate T-5 will create a new, additional market opportunity heretofore not available either to these potential suppliers.

Please refer to the Company's response to DR Items 7 and 9 of this Data Request concerning the Company's proposed $0.10/Mcf charge for alternate receipt point volumes.

15

Western Kentucky Gas Company
Case No. 99-070
WBI Southern, Inc. Data Request Dated September 14, 1999
DR Item 15
Witness: Smith

Data Request:

Explain why Rate T-5 is termed a "service" when it consists of only additional charges and limitations to services already being provided under Rates T-2, T-3 and T-4?

Response:

Western proposed the Rate T-5 tariff to establish a framework under which tariff transportation and carriage service customers could utilize an alternative receipt point into Westerns system. As indicated in the Company's response to DR Item 2 of this WBI-Southern Data Request, this option (the use of alternate receipt points) is not current available to these tariff transportation customers (also reference DR Item 8 of this request for additional information).

Rate T-5 is an additive, optional supplement to the Rate T-2, T-3 and T-4 services currently offered to its customers - opening up potential points of receipt and alternative routes for transportation via Westerns distribution system.

Please refer to the Company's response to DR Item 12 of this Data Request concerning the necessary restrictions on customer access to specific alternate receipt points and to DR Items 7 and 9 of this Data Request concerning the Company's proposed $0.10/Mcf charge for alternate receipt point volumes.

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OCT 04 1999

PUBLIC SERVICE
COMMISSION

JOHN N. HUGHES
Attorney at Law
Professional Service Corporation
124 WEST TODD STREET
FRANKFORT, KENTUCKY 40601

Telephone:
(502) 227-7270

Telecopier:
(502) 875-7059

October 4, 1999

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Lane
Frankfort, KY 40602

Re: Case No. 99-070

Dear Ms. Helton:

Please file the Responses of Western Kentucky Gas Company to the Commission's Third Request for Information, the Attorney General's Supplemental Request for Information, WBI Southern's Supplemental Request for Information, and its Petition for Confidentiality for certain of the responses. Item 58 of the Commission's request could not be completed to file today. It is expected to be available next week. Copies of these responses have been served on the intervenors.

Thank you for your assistance, and if there are any questions about this matter or if additional information is needed, please contact me.

Sincerely Yours,

John N. Hughes
Attorney for Western Kentucky
Gas Company

cc: Intervenors

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

OCT 04 1999

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY **Case No. 99-070**

PETITION FOR CONFIDENTIALITY OF CERTAIN INFORMATION PROVIDED IN RESPONSE TO DR ITEM 5 OF THE STAFF'S THIRD REQUEST FOR INFORMATION

Comes now Western Kentucky Gas Company ("Western"), pursuant to 807 KAR 5:001, Section 7, and all other applicable law, and for its Petition for Confidentiality, states as follows:

In Item No. 5 of the Staff's Third Request for Information, Western was requested to provide for each of Western's special contract customers the net revenues it would produce Western if billed at Western's tariffed rates, at both existing rates and the proposed rates. These calculations are set forth in the attached Schedule DR Item 5(a) & (d) and Schedule DR Item (b) & (c), which are marked as Exhibits A & B, respectively.

The information contained in Exhibits A & B reveal volume and discount levels for each special contract industrial customer for whom a discount has been negotiated, disclosure of all of which is necessary in order to provide the calculations requested by the Staff. The Commission has previously ruled in this proceeding that proprietary information of this nature is entitled to confidential protection for the reasons set forth below.

Pursuant to KRS 61.878(1)(c) the following documents are eligible for confidential treatment:

> "Upon and after July 15, 1992, records confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary which is openly disclosed would permit an unfair commercial advantage to competitors of the entity that disclosed the records--".

This is the same standard adopted by the Commission pursuant to 807 KAR 5:0001, Section 7. Company specific details concerning volumes and confidentially negotiated discounts with private enterprises are generally recognized as confidential and proprietary. Disclosure of details pertaining to a particular customer's volume and discount, are likely to cause substantial competitive harm to Western. Knowledge of these facts will provide Western's competitors with a substantial advantage in future business negotiations with Western's customers. Western's competitors would have clear advantage in competing for these customers since knowledge of existing Western discounts would enable them to slightly undercut Western's charges. On the other hand, Western's unregulated competitors are nor required to make public similar information.

Accordingly, the value of the information is derived by not being readily ascertainable by Western's competitors who would have a clear economic advantage upon disclosure. Negotiations concerning the discounts were maintained with strict confidentiality. None of this information is posted or otherwise generally made available within the company or without. Only those employees of Western who have a legitimate need to know have knowledge of the information contained in Exhibits A & B.

Additionally, disclosure of this information would put Western at a disadvantage in future negotiations of special contracts with other industrial customers. There would be little room for bargaining when a potential customer knows exactly what discounts Western has negotiated with other industrial customers. This likewise would put Western at an unfair commercial disadvantage.

WHEREFORE, Western respectfully requests that the attached Exhibits A & B be treated as confidential. One copy of the attached Exhibits have been submitted with the confidential portions highlighted for review and consideration by the Commission. Redacted copies of these documents have been submitted with Western's filing.

Respectfully submitted this 4 day of October, 1999.

Douglas Walther
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265

SHEFFER - HUTCHINSON - KINNEY
Mark R. Hutchinson
115 E. Second St.
Owensboro, KY 42303

John N. Hughes
124 West Todd Street
Frankfort, KY 40601

Attorneys for Western
Kentucky Gas Company

By:_______________

VERIFICATION

I, Gary Smith, being duly sworn under oath, state that I am Vice President of Marketing of Western Kentucky Gas Company, and that the foregoing statements are true of my own knowledge except as to those matters therein stated on information and belief, and as to those matters I believe them to be true.

Gary Smith

STATE OF KENTUCKY
COUNTY OF DAVIESS

SUBSCRIBED AND SWORN to before me by Gary Smith on this the 4 day of October, 1999.

Bonnie Krahwinkel
Notary Public
My Commission: 7|30|2000

CERTIFICATE OF SERVICE

I hereby certify that on the 4 day of October, 1999, this Petition, together with fifteen (15) copies, was filed with the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40602, and a true copy thereof mailed by first class mail to the following named persons:

Hon. David Spenard
Assistant Attorney General
Office of Rate Intervention
1024 Capitol Center Drive
Frankfort, Kentucky 40601

Hon. Mel Camenisch, Jr.
Stoll, Keenon & Park, LLP
201 E. Main Street
Suite 1000
Lexington, Kentucky 40507-1380

Mark R. Hutchinson

wkg\psc\rate\dritem5 of third request for information

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
OCT 04 1999
PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

RATE APPLICATION OF WESTERN KENTUCKY GAS COMPANY

Case No. 99-070

PETITION FOR CONFIDENTIALITY OF CERTAIN INFORMATION PROVIDED IN RESPONSE TO DR ITEM I OF THE STAFF'S THIRD REQUEST FOR INFORMATION

Comes now Western Kentucky Gas Company ("Western"), pursuant to 807 KAR 5:001, Section 7, and all other applicable law, and for its Petition for Confidentiality, states as follows:

In Item No. 1 of the Staff's Third Request for Information, Western was requested to provide certain information concerning the termination of the original gas supply agreement with Reliant Energy Services ("Reliant") and the new gas supply agreement with Woodward Marketing, LLC ("Woodward"). Subpart (c) requests Western to provide a detailed explanation for why it selected the next best proposal from the original vendors rather than re-open the bidding process. Western has previously provided this explanation in the attached letters which have already been granted confidential protection by the Commission in Case No. 97-513. These letters remain entitled to confidential treatment for the same reasons set forth in Western's previously filed Petition for Confidentiality.

Subpart (f) requests the terms of the termination agreement with Reliant. A redacted copy of the Reliant Termination Agreement is being filed in the public record and an unredacted copy is filed herewith. The only item of information in the Termination Agreement being redacted has previously been granted confidential protection by the Commission in Case No. 97-513 and for the same reasons is entitled to protection in this proceeding.

WHEREFORE, Western respectfully request that the attached documents be treated as confidential. One copy of the attached response has been submitted with the confidential portions highlighted for review and consideration by the Commission. Redacted copies of these documents have been submitted with Western's filing.

Respectfully submitted this 4 day of October, 1999.

Douglas Walther
Atmos Energy Corporation
P.O. Box 650205
Dallas, TX 75265

SHEFFER - HUTCHINSON - KINNEY
Mark R. Hutchinson
115 E. Second St.
Owensboro, KY 42303

John N. Hughes
124 West Todd Street
Frankfort, KY 40601

Attorneys for Western
Kentucky Gas Company

By: ______________________

VERIFICATION

I, Gary Smith, being duly sworn under oath, state that I am Vice President of Marketing of Western Kentucky Gas Company, and that the foregoing statements are true of my own knowledge except as to those matters therein stated on information and belief, and as to those matters I believe them to be true.

Gary L Smith

Gary Smith

STATE OF KENTUCKY
COUNTY OF DAVIESS

SUBSCRIBED AND SWORN to before me by Gary Smith on this the 4th day of October, 1999.

Bonnie Krahwinkel

Notary Public
My Commission: 7/30/2000

CERTIFICATE OF SERVICE

I hereby certify that on the 4 day of October, 1999, this Petition, together with fifteen (15) copies, was filed with the Kentucky Public Service Commission, 730 Schenkel Lane, Frankfort, Kentucky 40602, and a true copy thereof mailed by first class mail to the following named persons:

Hon. David Spenard
Assistant Attorney General
Office of Rate Intervention
1024 Capitol Center Drive
Frankfort, Kentucky 40601

Hon. Mel Camenisch, Jr.
Stoll, Kennon & Park, LLP
201 E. Main Street
Suite 1000
Lexington, Kentucky 40507-1380

Mark R. Hutchinson

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COMMISSION

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 1-a, b, c, d, e, f
Witness: Hack

Data Request:

Refer to the response to Item 42 of the Commission's August 19, 1999, Order. The original agreement between Western and Reliant Energy Services ("Reliant") had been filed with the Commission by Western.

a. Has Western filed the replacement agreement of Woodward Marketing, LLC ("Woodward") with the Commission at this time?

b. When does Western expect to file the new agreement with the Commission?

c. Provide a detailed explanation for why Western decided to go with the next best proposal from the original vendors rather than re-open the process by requesting new bids.

d. Explain whether Western could have re-opened the process by requesting new bids from vendors other than Woodward, and then gone back to Woodward if its original proposal was still better than the new bids.

e. What is the corporate relationship between Western and Woodward?

f. The original agreement between Western and Reliant was terminated by mutual agreement of the parties. Provide the terms of the termination of the agreement and the impact that the termination has had, or will have, on the costs recovered through Western's Gas Cost Adjustment ("GCA") clause.

Response:

a. - b. Western expects to file the Woodward replacement agreement with the Commission by October 4, 1999.

c. See the attached redacted letters explaining why Western decided to go with the next best proposal from the original vendors. Original copies of these letters are being provided in this case under Petition for Confidentiality. These letters were granted confidentiality when previously submitted to the Commission in Case No. 97-513.

d. No. In order for Western to maintain fairness and complete integrity of its bid process, had it decided to re-bid its requirements, it would have had to reopen the bidding to all of the qualified suppliers on its active bid list except for Reliant Energy.

e. Atmos, through its acquisition of United Cities Gas Company in 1997, owns a 45% interest in Woodward Marketing, LLC. See KPSC #1 - DR 1

f. The Reliant/WKG agreement was terminated July 31, 1999, with 23 months remaining on the original 3-year term. See attached redacted termination agreement, the original of which is being provided in this case under Petition for Confidentiality. Had the Reliant contract continued for the entire term, Western's customers would have received gas cost reductions through its GCA mechanism of approximately $2.6 million for the remaining 23 months. Combining the benefits of the Woodward replacement agreement with the Reliant Contract buyout, Western's customers will receive approximately $2.5 million in gas cost reductions through the GCA mechanism over the remaining term.

Western Kentucky Gas Company

WESTERN KENTUCKY GAS

April 23, 1999

Honorable Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Drive
Frankfort, Kentucky 40602

Subject: **KPSC Case No. 97-513 – Western Kentucky Gas Company Experimental Performance-Based Ratemaking Mechanism**

Gas Supply Management Contract

Dear Ms. Helton:

THIS LETTER CONTAINS INFORMATION WHICH THE COMMISSION HAS PREVIOUSLY DETERMINED IS ENTITLED TO CONFIDENTIAL PROTECTION AND SHALL BE WITHHELD FROM PUBLIC INSPECTION. WE ASK THAT THE SAME PROTECTION BE AFFORDED THIS LETTER.

As you may recall, during 1997 Western Kentucky Gas Company requested authorization from the Commission to implement an Experimental Performance-Based Ratemaking Mechanism (PBR). In KPSC Case No. 97-513 which was finalized in June 1998, the Commission authorized the Western Kentucky Gas Company Experimental Performance-Based Ratemaking Mechanism for a three-year period beginning July 1, 1998.

After learning that the PBR mechanism had been approved, WKG distributed a Request for Proposal (RFP) to more than forty suppliers seeking to obtain competitive bids to manage WKG's commodity, pipeline transportation and storage requirements. Of the original forty-three vendors solicited for bids, only eight vendors submitted bids that were accepted as qualifying bids. That is, the bids submitted fully complied with the requirements outlined in the RFP. Each vendor was requested to submit bids for commodity purchases on a plus or minus basis per MMBtu for the appropriate supply area index. A listing of the vendors who submitted conforming bids and the amounts bid follows:

Company	Index Price +/- per MMBtu
[redacted]	[redacted]

standard industry practice under competitive bidding where the top bid, under more careful review, is determined not to be superior to the next highest bid under the complete terms of the RFP. The second best bid received was from [redacted] has indicated its willingness to serve as the asset manager for the remaining two years of the PBR, from July 1, 1999, to June 30, 2001. It also has said that it will honor its bid of last summer at the same commodity rate of [redacted] subject to the negotiation of a mutually agreeable contract.

The Noram bid was [redacted] The effect of the buyout by Noram over the last two years of the contract is approximately [redacted] if you assume annual purchase volumes of 26 Bcf. By combining the Noram buyout with the [redacted] bid, we would end up with a [redacted] on a per unit basis compared to Noram's [redacted] The net reduction of PBR benefit for the remaining two years of the experimental PBR program would amount to [redacted] for customers and an equal amount for the Company.

Option 3. If we accept the Noram buyout, we could also re-bid the contract. This could result in an increase in gas cost to the customer. WKG has no reason to believe that it can achieve a price in rebidding the contract better than the [redacted] We believe bidders will be reluctant to take as much risk now knowing that Noram opted out of the contract, and in reaction to the current market conditions. While we would expect [redacted] to re-bid, there are certainly no guarantees that [redacted] would bid the same amount as last time. [redacted] With 52 MMBtu of purchase requirements, this amounts to more than a [redacted] reduction in savings, more than [redacted] less each for customers and shareholders.

WKG believes that Option 2 is the best overall option and proposes to pursue this option. However, we want to be sure that the Commission and Commission staff are satisfied [redacted] We believe WKG is in compliance. We would like to meet with Commission staff as soon as possible to have some dialogue on this development, and I will call the Commission within the next few days to try to schedule a meeting.

If you have any questions, please feel free to call me at 502-685-8072.

Sincerely yours,

Bill Senter

William J. Senter
VP Rates & Regulatory Affairs

cc: Ms. Becky Phillips

Western Kentucky Gas Company

WESTERN
KENTUCKY
GAS

June 29, 1999

Honorable Helen C. Helton
Executive Director
Kentucky Public Service Commission
730 Schenkel Drive
Frankfort, Kentucky 40602

Subject: **KPSC Case No. 97-513 – Western Kentucky Gas Company Experimental Performance-Based Ratemaking Mechanism**

Gas Supply Management Contract

Dear Ms. Helton:

THIS LETTER CONTAINS INFORMATION WHICH THE COMMISSION HAS PREVIOUSLY DETERMINED IS ENTITLED TO CONFIDENTIAL PROTECTION AND SHALL BE WITHHELD FROM PUBLIC INSPECTION. WE ASK THAT THE SAME PROTECTION BE AFFORDED THIS LETTER.

In my April 23, 1999 letter to you and a subsequent meeting held May 12 with the Staff and the Attorney General's office, Western Kentucky Gas Company outlined the situation that has developed whereby our present gas supplier under our Performance-Based Ratemaking Mechanism (PBR), Reliant Energy Services (formerly NorAm), has expressed the desire to buy out the remaining term of their contract with us. Reliant's purpose is to eliminate continuing losses to Reliant resulting from an over-aggressive bid last year. Reliant's proposal is summarized in the attached letter of confirmation.

As discussed in my letter and in person with the Staff and Attorney General's office, Western's goal has always been to achieve the maximum benefit for our customers and Western under the PBR. Given the various options faced by Western as a result of the Reliant situation, Western believes the best decision is to allow Reliant to buy out its contract and award the remaining term to the next highest bidder, Woodward Marketing (Option 2). Woodward's bid was far superior to the other bids received and Woodward has indicated its willingness to honor its original bid. Additionally, we have no concerns about Woodward's ability and intent to perform through the end of the original contract term. Given the uncertainty associated with Reliant and considering that overall market conditions are less favorable today compared to when the original bids were received, we are confident that this decision will achieve the goal of maximum customer benefit under the PBR.

2401 New Hartford Road Owensboro, KY 42303 Phone: (502) 685-8150 Fax: (502) 685-8052

Our purpose with this letter was to simply inform you of our decision. We appreciate the Staff's willingness to listen to our concerns and discuss the issue with us. Please feel free to contact me at 270-685-8072 should you have any questions. Upon successful negotiation and execution of all the terms of the contract with Woodward, we will file a copy with the Commission.

Sincerely,

William J. Senter jp

William J. Senter
Vice President – Rates & Regulatory Affairs

Attachment

Cc: Mr. Conrad Gruber
Mr. Gordon Roy
Mr. Randy Hutchinson
Mr. Jack Hughes

Reliant Energy™

June 25, 1999

Atmos Energy Corporation
Mr. Gordon J. Roy
Vice President, Gas Supply

Re: Natural Gas Sales, Purchase, Transportation and Storage Agreement dated July 1, 1998.

Dear Sir;

We appreciate your response to our letter which you referenced as having received on June 9, 1999, regarding the agreement between Western Kentucky Gas Company, a division of Atmos Energy Corporation ("WKG"), and Reliant Energy Services, Inc. (as successor in interest to Noram Energy rvices, Inc.) ("Reliant").

Your understanding of our proposal is fundamentally correct; Termination of the Agreement for [redacted] consideration to be paid by Reliant to WKG. In addition, we would require "excess" gas in storage to be purchased from Reliant by WKG at the then current market price.

Our proposal is contingent on our management's final approval.

We welcome your interest in our proposal and look forward to your response.

Sincerely,

Ken Bradley

Ken Bradley
Managing Director, Storage, Transportation and Asset Optimization
Reliant Energy Services

This proposal is not intended to create a binding offer or contract of purchase and sale of gas between Buyer and Seller. Moreover, this document does not in any way whatsoever obligate either of the parties to enter into any agreements or to proceed with any possible relationship or transaction under the terms and conditions set forth herein. The terms and conditions forth are subject to negotiation, completion and incorporation into and the execution by both parties of a definitive ement. Either party may terminate discussions and/or negotiations regarding this document at any time.

TERMINATION AGREEMENT

This Termination Agreement is made and shall be effective as of the 31st day of July, 1999 by and between Reliant Energy Services Corporation ("Reliant") whose address is P. O. Box 4455, Houston, Texas 77210-4455 and Western Kentucky Gas Company, a division of Atmos Energy Corporation ("WKG") whose address is P. O. Box 650205, Dallas, Texas 75265-0205.

WHEREAS, Noram Energy Services, Inc. and WKG are parties to that certain Natural Gas Sales, Purchase, Transportation and Storage Agreement ("Agreement") that became effective as of July 1, 1998; and

WHEREAS, Reliant has succeeded to the rights, title and interests of Noram Energy Services, Inc., with respect to the Agreement; and

WHEREAS, Reliant and WKG now wish to terminate the Agreement pursuant to the terms and conditions contained in the Agreement as such terms are further described herein:

NOW THEREFORE, in considerations of the mutual promises, covenants and agreements herein contained Reliant and WKG agree as follows:

1. Pursuant to Article XIV, "TERMINATION AND EARLY TERMINATION," the Agreement shall be terminated as of July 31, 1999. Upon such termination, neither party shall have any further duty to the other party pursuant to the Agreement except as such duty is described herein.

2. As consideration for such termination, Reliant shall pay to WKG a one time, non-recoupable payment in the amount [redacted] Reliant shall pay such sum to WKG upon execution by WKG hereof.

3. Upon execution hereof, the parties shall immediately proceed to "wind up" all existing outstanding transactions. As of July 1, 1999, the parties estimate that there is an imbalance of 3,921,071 Mcf for which WKG owes Reliant the price described in Article VI, Section 1 of the Agreement plus applicable transportation cost pursuant to the Storage Plan Schedule (the "Plan"). The parties will agree upon the actual amount of such imbalance as of July 31, 1999, and WKG will pay Reliant for such volume at the price described in said Article VI and according to the Plan as such has been agreed to pursuant to the Agreement as follows: (a) on or before August 31, 1999, WKG shall pay Reliant for ~~1,559,000~~ MMBtu; (b) on 1,340,000
or before September 30, 1999, WKG shall pay Reliant for ~~1,340,000~~ MMBtu; (c) 1,028,000
if the agreed upon imbalance has not been satisfied as of September 30, 1999, WKG shall pay Reliant for any such remaining imbalance pursuant to the Plan. All other matters pertaining to the Agreement between the parties shall be done

pursuant to Section 1, "Winding Up Arrangements" of Article XVI "MISCELLANEOUS" of the Agreement.

IN WITNESS THEREOF, the parties have executed this Agreement as of the date first written above.

Reliant Energy Services, Inc.

By: Patrick J. Strange

Title: PATRICK J. STRANGE
Vice President
Gas Trading and Operations

Date: 7/16/99

Western Kentucky Gas Company, a Division of Atmos Energy Corporation

By: Gordon J. Lay

Title: Vice-President

Date: 7-23-99

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 2
Witness: Gary Smith

Data Request:

Refer to the response to Item 43 of the Commission's August 19, 1999 Order and the proposed Weather Normalization Adjustment ("WNA") tariff at Tab 6 in Volume 1 of 10 of the application.

a. Clarify the response to Item 43. Would Western be opposed to its WNA being implemented on a pilot basis?

b. As stated in the prior request, Western's proposed WNA tariff differs from the WNA tariff of Columbia Gas of Kentucky ("Columbia") in some respects. Provide an example calculation, based on the formula in the proposed tariff, of the impact of the WNA on a representative residential customer's bill, during both a colder-than-normal month and a warmer-than-normal month.

Response:

a. As stated in Westerns response to Item 43 (c) of the Commission's August 19, 1999 Order, the Company would not oppose the implementation of its proposed WNA on a pilot basis.

b. Attached hereto, as Exhibit KPSC #3 - Item 2, are example calculations, based on the formula in the proposed tariff, of the impact of the WNA on a representative residential customer's bill, during both a colder-than-normal month (Sheet 1 of 2) and a warmer-than-normal month (Sheet 2 of 2). Assumptions and references are provided for purposes of computing the WNA and the total customer billings.

Western Kentucky Gas Company
Case 99-070
Kentucky Public Service Commission Data Request Dated September 20, 1999

Impact of the WNA on a Representative Residential Customer's Bill, During a Colder-than-normal Month

Line No.	Item	Calculated Value	Source/Calculation Method
	(a)	(b)	(c)
1	Normal Lagged Degree-Days, January =	933	Volume 2 of 10, Tab 11 of the Company's Application,
2			Exhibit GLS-4, Sheet 2 of 5, Column (e) line 5.
3			
4	Lagged Degree-Days, @ 10% colder than normal =	1,026	Column b, line 1 times 110%
5			
6	Heat Sensitive Factor (residential), Mcf/degree-day/customer=	0.0154	AG DR No. 1, Item 152, Sheet 1 of 4, column h, line 17
7			
8	Base Load Factor (residential), Mcf/month/customer=	1.5444	AG DR No. 1, Item 151, column f, line 8
9			
10	Weighted Average Rate ("R") for residential class,		
11	at Proposed Rates =	1.2000	AG DR No. 1, Item 153, Sheet 1 of 1, column h, line 8
12			
13	Calculated WNA, at Proposed Rates, at 10% colder	(0.0991)	Formula stated in proposed tariff at First-revised Sheet
14	than Normal Weather (ADD = 1,026)		No. 26, applying the factors above on this Schedule.
15			
16	Representative Residential Usage Estimate, January =	17.3	Column b, line 4 times Column b, line 6 plus
17			Column b, line 8
18			
19	Assumed Gas Charge per Mcf, January =	$3.4023	Estimated Firm Gas Cost (Not including margin),
20			PSC DR No. 2, Item 47(b), Exhibit, Page 2 of 3.
21			
22	Proposed Distribution Charge per Mcf =	$1.2000	Proposed G-1 tariff at Third Revised Sheet No. 11
23			
24	Proposed Monthly Base Charge =	$9.00	Proposed G-1 tariff at Third Revised Sheet No. 11
25			
26	Representative Residential Customer Bill, excluding	$88.62	Column b, line 24 plus Column b, line 16 times
27	taxes - without WNA, @ 17.3 Mcf =		(Column b, line 19 plus Column b, line 22)
28			
29	Representative Residential Customer Bill, excluding	$86.91	Column b, line 24 plus Column b, line 16 times
30	taxes - including WNA @ 17.3 Mcf =		(Column b, line 19 plus Column b, line 22 plus
31			Column b, line13)

Western Kentucky Gas Company
Case 99-070
Kentucky Public Service Commission Data Request Dated September 20, 1999

Impact of the WNA on a Representative Residential Customer's Bill, During a Warmer-than-normal Month

Line No.	Item (a)	Calculated Value (b)	Source/Calculation Method (c)
1	Normal Lagged Degree-Days, January =	933	Volume 2 of 10, Tab 11 of the Company's Application,
2			Exhibit GLS-4, Sheet 2 of 5, Column (e) line 5.
3			
4	Lagged Degree-Days, @ 10% warmer than normal =	840	Column b, line 1 times 90%
5			
6	Heat Sensitive Factor (residential), Mcf/degree-day/customer=	0.0154	AG DR No. 1, Item 152, Sheet 1 of 4, column h, line 17
7			
8	Base Load Factor (residential), Mcf/month/customer=	1.5444	AG DR No. 1, Item 151, column f, line 8
9			
10	Weighted Average Rate ("R") for residential class,		
11	at Proposed Rates =	1.2000	AG DR No. 1, Item 153, Sheet 1 of 1, column h, line 8
12			
13	Calculated WNA, at Proposed Rates, at 10% warmer	0.1187	Formula stated in proposed tariff at First-revised Sheet
14	than Normal Weather (ADD = 840)		No. 26, applying the factors above on this Schedule.
15			
16	Representative Residential Usage Estimate, January =	14.5	Column b, line 4 times Column b, line 6 plus
17			Column b, line 8
18			
19	Assumed Gas Charge per Mcf, January =	$3.4023	Estimated Firm Gas Cost (Not including margin),
20			PSC DR No. 2, Item 47(b), Exhibit, Page 2 of 3.
21			
22	Proposed Distribution Charge per Mcf =	$1.2000	Proposed G-1 tariff at Third Revised Sheet No. 11
23			
24	Proposed Monthly Base Charge =	$9.00	Proposed G-1 tariff at Third Revised Sheet No. 11
25			
26	Representative Residential Customer Bill, excluding	$75.73	Column b, line 24 plus Column b, line 16 times
27	taxes - without WNA, @ 17.3 Mcf =		(Column b, line 19 plus Column b, line 22)
28			
29	Representative Residential Customer Bill, excluding	$77.45	Column b, line 24 plus Column b, line 16 times
30	taxes - including WNA @ 17.3 Mcf =		(Column b, line 19 plus Column b, line 22 plus
31			Column b, line13)

Notes

3

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3
Witness: Gary Smith

Data Request:

Refer to the response to Item 44 of the Commission's August 19, 1999 Order. The comparison of December 1998 to December 1999 meters in service and the comparison of June 1998 to June 1999 meters in service both reflect larger increases than the March 1998 to March 1999 comparison included in the Direct Testimony of Gary L. Smith.

a. Explain why the March 1998 to March 1999 comparison of meters in service was chosen to be included in Mr. Smith's testimony.

b. As soon as available, provide a September 1998 to September 1999 comparison of meters in service in the same format as the other comparisons that have been provided. Indicate in this response the date the information will be filed.

c. The response to Item 44 shows a change of 1,983 residential customers from December 1997 to December 1998, while the table on page 12 of Mr. Smith's testimony shows a change of 1,722. Explain the reasons for these differences and explain how "Average meters in service fiscal year to date" as shown in the response differs from "Residential meters in service," which is the heading in the table in Mr. Smith's testimony.

Response:

a. The referenced testimony, at page 7, line 28 through page 8, line 3, compares the projected meter growth rate included in the FY 1999 budget versus the actual growth experienced, to date, for the period. The annual growth rate through March 1999 was chosen since that was the most current information available at the time the testimony was prepared.

b. We expect that the requested information can be filed by November 15, 1999.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3
Witness: Gary Smith

c. The response to Item 44, as noted in this question, compares the numeric average meters in service for the fiscal year to date for December 1998 to December 1997 (the average of the months October, November and December for the respective fiscal year).

The table included in the referenced testimony at page 12, lines 1-9, compares the number of meters in service during the month of December. In other words, the table in testimony is not the numeric average of the months of October, November and December for the respective period. For additional information regarding this table in testimony, please also refer to the Company's response to the KPSC Data Request Dated July 16, 1999, Item 58 (c).

Notes

4

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 4 (a)
Witness: Gary Smith

Data Request:

Refer to the response to Item 46 of the Commission's August 19, 1999 Order.

a. Provide an explanation for the decline in the number of Public Authority customers from fiscal year 1998 to the 12 months ended June 30, 1999.

Response:

a. The Company conducted an ad-hoc analysis of billing data for the referenced periods. A summary of the analysis is attached as Exhibit KPSC DR #3 - Item 4 (a).

As shown in the summary, ten new customers have been added during the period, and 31 public authority customers have discontinued service. The timing of the additions and losses is shown to determine the impact of these changes in the computation of 12-months average meters in service for the two periods noted. Please note that gas service to 8 of the public authority account losses was subsequently re-established to a commercial class occupant. Additionally, 100 public authority accounts requested turn-off seasonally; the "cycling" of these seasonal customers did not affect the decline in public authority class meters in service in the comparison of these periods.

Exhibit KSPC DR 3
Item 4 (a)

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 4 (a)
Witness: Gary Smith

Line No.	Account	Description	Month	Year	# Bills for FY 1999	# Bills for 12 mo. Ending June 1999
	(a)	(b)	(c)	(d)	(e)	(f)
1	Customer 1	Final	10	1997	1	0
2	Customer 2	Final	10	1997	1	0
3	Customer 3	Final	11	1997	2	0
4	Customer 4	Turn On	11	1997	11	12
5	Customer 5	Turn On	11	1997	11	12
6	Customer 6	Turn On	11	1997	11	12
7	Customer 7	Turn On	11	1997	11	12
8	Customer 8	Final {1}	12	1997	3	0
9	Customer 9	Turn On	12	1997	10	12
10	Customer 10	Turn On	12	1997	10	12
11	Customer 11	Turn On	1	1998	9	12
12	Customer 12	Final	2	1998	5	0
13	Customer 13	Turn On	2	1998	8	12
14	Customer 14	Final	3	1998	6	0
15	Customer 15	Turn On	3	1998	7	12
16	Customer 16	Final	4	1998	7	0
17	Customer 17	Final {1}	4	1998	7	0
18	Customer 18	Final {1}	5	1998	8	0
19	Customer 19	Final	5	1998	8	0
20	Customer 20	Final	5	1998	8	0
21	Customer 21	Final	5	1998	8	0
22	Customer 22	Final	7	1998	10	1
23	Customer 23	Final	7	1998	10	1
24	Customer 24	Final {1}	7	1998	10	1
25	Customer 25	Final	7	1998	10	1
26	Customer 26	Final {1}	8	1998	11	2
27	Customer 27	Final	9	1998	12	3
28	Customer 28	Final {1}	10	1998	12	4
29	Customer 29	Final	10	1998	12	4
30	Customer 30	Final {1}	11	1998	12	5
31	Customer 31	Final	11	1998	12	5
32	Customer 32	Final	12	1998	12	6
33	Customer 33	Final {1}	1	1999	12	7
34	Customer 34	Final	2	1999	12	8
35	Customer 35	Turn On	2	1999	0	5
36	Customer 36	Final	3	1999	12	9
37	Customer 37	Final	5	1999	12	11
38	Customer 38	Final	5	1999	12	11
39	Customer 39	Final	5	1999	12	11
40	Customer 40	Final	5	1999	12	11
41	Customer 41	Final	5	1999	12	11
42						
43	Total Number of Bills for These 41 P/A Accounts=				371	225
44						
45	Change in Total Number of Bills for These 41 P/A					
46	Accounts (Col. f, Line 43 - Col. e, Line 43) =					(146)
47						
48	Change in Average Total Number of Bills for These 41					
49	P/A Accounts per month (Col. f, Line 46 divided by 12) =					(12)
50						
51	{1} - Service to the noted premises was later re-established; however, the subsequent					
52	occupant was a Class 2, Commercial account.					

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 4 (b) - (d)
Witness: Gary Smith

Data Request:

Refer to the response to Item 46 of the Commission's August 19, 1999 Order.

b. As soon as available, provide an updated version of the response to Item 46(a), which substitutes fiscal year 1999 for the 12 months ended June 30, 1999. Indicate in this response the date the information will be filed.

c. The response to Item 46(b) provides weather-adjusted volumes by customer class, with Sheet 2 of 2 providing supporting calculations for the information shown on Sheet 1 of 2. Refer to the volumes for fiscal year 1996. Should the weather adjustment have resulted in a decrease from actual volumes rather than the increase shown when comparing responses 46(a) and 46(b)? If yes, provide Sheet 1 of 2 with the necessary revisions to the fiscal year 1996 volumes.

d. As soon as available, provide an updated version of response 46(b) that substitutes fiscal year 1999 for the 12 months ended June 30, 1999. Indicate in this response the date the information will be filed.

Response:

b. We expect that the requested information can be filed by November 15, 1999.

c. Yes. Upon receipt of this question, we discovered a formula error affecting the calculations for the weather adjustment for both FY 1996 and FY 1995. The revised Exhibits are attached hereto.

d. We expect that the requested information can be filed by November 15, 1999.

REVISED
PSC DR NO. 2
DR Item 46 (b)
Sheet 1 of 2

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #2 Dated August 19, 1999
DR Item 46 (b)
Witness: Smith

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
1	**Degree-Days:**					
2	(Source - NOAA, Composite)					12-mo Ending
3		FY 1995	FY 1996	FY 1997	FY 1998	6/30/99
4	Actual, Calendar Month	3,665	4,748	4,315	4,013	3,701
5	Normal	4,340	4,340	4,340	4,340	4,340
6	Percent Normal	84.4%	109.4%	99.4%	92.5%	85.3%
7						
8						
9	**Weather Adjusted Volumes, by Class, in Mcf:**					
10	(Source - Refer to Sheet 2 of 2 of this Exhibit for Calculation of Volume Adjustment. The Volume adjustments are					
11	added to the Volumes reported in Western's Financial Statements, summarized in PSC DR2 - Item 46 a)					
12						
13						12-mo Ending
14		FY 1995	FY 1996	FY 1997	FY 1998	6/30/99
15	Residential	13,804,209	13,706,757	13,399,066	13,385,689	13,288,850
16	Commercial	5,857,762	6,008,165	5,999,613	5,880,976	5,697,778
17	Industrial	9,992,575	10,725,745	6,128,597	3,414,638	2,891,547
18	Public Authority	1,622,463	1,575,617	1,537,439	1,552,003	1,506,096
19	Unbilled	(55,705)	(24,136)	320,531	(222,854)	(69,466)
20	Total Sales Customers	31,221,304	31,992,148	27,385,246	24,010,452	23,314,804
21						
22	Transportation Customers	17,103,124	16,935,972	22,398,363	25,812,786	25,082,734
23						
24	TOTAL DELIVERIES	48,324,428	48,928,120	49,783,609	49,823,238	48,397,538
25						

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #2 Dated August 19, 1999
DR Item 46 (b)
Witness: Smith

Line No.	Item	FY 1995	FY 1996	FY 1997	FY 1998	12-mo Ending June 1999	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Weather Statistics						
2	Degree-Days, Actual Calendar Month	3,665	4,748	4,315	4,013	3,701	NOAA, Composite
3	Degree-Days, Normal	4,340	4,340	4,340	4,340	4,340	NOAA, Composite
4							
5	Weather Sensitive Volumes						
6	Residential Sales (incl Unbilled)	13,657,999	12,338,322	13,657,999	12,338,322	11,689,716	Financial Statements
7	Commercial Sales	5,977,762	5,604,480	5,977,762	5,604,480	5,139,484	Financial Statements
8	Public Authority Sales	1,531,144	1,461,600	1,531,144	1,461,600	1,344,628	Financial Statements
9							
10	Residential Base Load per Month	170,506	199,187	252,184	184,980	235,841	Financials, Avg Prior July&Aug
11	Commercial Base Load per Month	195,496	185,787	183,850	184,273	158,827	Financials, Avg Prior July&Aug
12	Pub. Auth. Base Load per Month	33,701	32,318	37,051	29,347	34,119	Financials, Avg Prior July&Aug
13							
14	Residential Heating Load/DD	2,691	2,479	2,464	2,521	2,394	(Line 6-(Line10x12mo))/Line 2
15	Commercial Heating Load/DD	842	841	874	846	874	(Line 7-(Line11x12mo))/Line 2
16	Pub. Auth. Heating Load/DD	261	268	252	276	253	(Line 8-(Line12x12mo))/Line 2
17							
18	Residential Adjustment - Volume	1,816,467	(1,011,417)	61,598	824,513	1,529,668	Line 14x(Line 2-Line 3)
19	Commercial Adjustment - Volume	568,128	(343,138)	21,851	276,496	558,294	Line 15x(Line 2-Line 3)
20	Pub. Auth. Adjustment - Volume	176,256	(109,172)	6,295	90,403	161,468	Line 16x(Line 2-Line 3)
21	Total Volume Adjustment - Weather	2,560,851	(1,463,727)	89,744	1,191,412	2,249,429	

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 5
Witness: Gary Smith

Data Request:

Refer to the response to Item 47(c) of the Commission's August 19, 1999 Order.

a. The response indicates that 13 customers, with adjusted volumes totaling 13,332,103 Mcf, will generate total net revenues of $1,692,428 under present margins (contract rates). Identifying them as Customer A, Customer B, etc., provide for each customer the net revenues it would provide Western if it were billed Western's tariffed rates, at both the existing rates and the proposed rates.

b. For the 13 customers as a group, provide the total volumes of 13,332,103 Mcf separated into the categories of Firm Carriage Service and Interruptible Carriage Service.

c. Based on the response to part (b) of this request, provide the total net revenues, under present margins, generated by Firm Carriage Service and Interruptible Carriage Service.

d. Based on the response to part (b) of this request, provide the total net revenues that this group of customers would provide for Firm Carriage Service and for Interruptible Carriage Service if they were billed Western's tariffed rates, at both the existing rates and the proposed rates.

Response:

The schedules attached hereto are filed under a petition for confidentiality due to the necessity of revealing the affected volume and/or discount level for purposes of these computations.

a. Please reference the attached schedule, DR Item 5 (a) & (d) for the requested computation.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 5
Witness: Gary Smith

b. For these 13 customers as a group, the Firm Carriage Service volume is 4,717,242 Mcf and the Interruptible Carriage Service volume is 8,614,861 Mcf. Please reference the attached schedule, DR 5 (b) & (c) for the computation, by customer.

c. For these 13 customers as a group, the Firm Carriage Service margin is $425,038 and the Interruptible Carriage Service margin is $1,267,392. Please reference the attached schedule, DR 5 (b) & (c) for the computation, by customer.

d. Please reference the attached schedule, DR Item 5 (a) & (d) for the requested computation. Total net revenues, by service, for the group is found on Sheet 2 of 2 of the Exhibit, lines 26-33.

Western Kentucky Gas Company
Case 99-070
KPSC DR#3, Item 5 (a) & (d)
Witness: Smith
REDACTED COPY

Line No.	Description	Service Type	Tariff Billing Blocks (Mcf)	Test Year Volumes Into Billing Blocks (Mcf)	Present Tariff Rates	Net Revenues If Billed Present Tariff Rates	Proposed Tariff Rates	Net Revenues If Billed Present Tariff Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1								
2								
3								
4								
5								
6								
7								
8								
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CONFIDENTIAL
DR Item 5 (a) & (d)
Schedule 2 of 2

Western Kentucky Gas Company
Case 99-070
KPSC DR#3, Item 5
Witness: Smith

Line No.	Description	Service Type	Tariff Billing Blocks (Mcf)	Test Year Volumes Into Billing Blocks (Mcf)	Present Tariff Rates	Net Revenues If Billed Present Tariff Rates	Proposed Tariff Rates	Net Revenues If Billed Present Tariff Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1								
2								
3								
4								
5								
6								
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CONFIDENTIAL
DR Item 5 (b) & (c)

Western Kentucky Gas Company
Case 99-070
KPSC DR#3, Item 5 (b) & (c)
Witness: Smith

REDACTED COPY

Line No.	Description	Service Type	Total Test Year Volumes	Present Margin	Present Revenue
	(a)	(b)	(c)	(d)	(e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 6a

Data Request:

Refer to the response to Item 48 of the Commission's August 19, 1999 Order and Revised Exhibits GLS-1 and GLS-2.

a. If Western's application did not employ a forecasted test year, but employed the historical test year ended September 30, 1998, normalized to reflect known and measurable adjustments, would Column (g) "Total Volumes" be the adjusted billing units on which rates would be calculated? If no, provide the adjusted billing units and explain how they would be determined.

Response:

The KPSC has amended this question and set a new response date of October 8, 1999.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 6 (b)
Witness: Gary Smith

Data Request:

Refer to the response to Item 48 of the Commission's August 19, 1999 Order and Revised Exhibits GLS-1 and GLS-2.

b. Refer to part (b) of the response. Explain how the 180,576 Mcf attributable to commercial customer growth was split between the "0 to 300 Mcf" rate block and the "301 to 15,000 Mcf" rate block.

Response:

b. The split between the "0 to 300 Mcf" rate block and the "301 to 15,000 Mcf" rate block for commercial customer growth volumes was based on the ratio of volumes in these billing blocks for volumes as metered, including large commercial contract adjustments. This computed ratio is 84%:16% respectively between the "0 to 300 Mcf" rate block and the "301 to 15,000 Mcf" rate block. This is the same commercial volume ratio utilized in the Weather Adjustment (GLS-4) and Conservation and Energy Adjustment (GLS-6). The following table provides the resources used in this computed ratio.

Commercial Firm Sales

Line No.	Tariff Billing Block, Mcf	Volumes per Books {1}	Contract Adjustments {2}	Volumes with Contr. Adj. {3}
	(a)	(b)	(c)	(d)
1				
2	0-300	5,520,335	(32,338)	5,487,997
3	301-15,000	1,206,676	(170,410)	1,036,266
4				6,524,263
5				
6	Computed Ratio of Firm Commercial Sales Volumes			
7	in the 0-300 Mcf Billing Block -			
8	Column (d), line 2, divided by Column (d), line 4 =			84%
9				
10	Notes: {1} Refer to Exhibit GLS-2, Column (f), Lines 4-5.			
11	{2} Refer to Exhibit GLS-3, Column (f), Lines 4-5.			
12	{3} Sum of Column (b) and Column (c) for the respective line.			

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 7
Witness: Gary Smith

Data Request:

Refer to the response to Item 49 of the Commission's August 19, 1999 Order and Exhibits GLS-2, GLS-4, GLS-5 and GLS-6 of the Direct Testimony of Gary L. Smith.

a. Item 49, Sheets 1, 2, and 3 of 9, were provided to support the declining trend in residential usage per customer. Is it correct that the total for Column (h), "Normalized Volumes," on each of these sheets reflects total volumes for the fiscal year identified at the top of the page?

b. Is it correct that the 13,034,849 Mcf at the top of Sheet 3, above Column (h), "Normalized Volumes," reflects the total volumes for the forecasted test year, calendar year 2000?

c. Refer to the aforementioned exhibits to Mr. Smith's testimony at Column (b), "Residential Mcf." These columns show, respectively, per book volumes, volume increases for weather, volume increases for customer growth, and volume decreases for conservation and energy efficiency. The net total, beginning with GLS-2 and going through GLS-6, is 13,026,240 Mcf. Explain why this number for residential Mcf for the forecasted test year does not match the 13,034,849 Mcf shown in the response on Sheet 3.

Response:

a. Column (h) of these sheets reflect the total normalized volumes per month for cycle billings during the noted month for the fiscal year noted at the top of the page. Column (j) reflects the total normalized volume per month, including changes in unbilled volumes for the noted month during the fiscal year noted at the top of the page.

b. The 13,034,849 Mcf reflects the total of the normalized volumes per month for cycle billings, Column (h) during the months of January 2000 through December 2000.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 7
Witness: Gary Smith

c. The sum of Column (j), which includes changes in unbilled volumes, for the months of January 2000 through December 2000 totals 13,026,239 Mcf. The forecasted test year is based on these monthly totals, including the unbilled volumes. The discrepancy of 1 Mcf between this figure and the net total, beginning with GLS-2 and going through GLS-6, of 13,026,240 Mcf is attributable to rounding differences between these spreadsheets.

8

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 8
Witness: Gary Smith

Data Request:

Refer to the response to Item 51 of the Commission's August 19, 1999 Order. Given Western's GCA tariff provision requiring annual Balancing Adjustment filings in February, would it be preferable for Western to make its February filing and then begin a quarterly GCA filing schedule with a filing schedule of February, May, August, and November?

Response:

Western would be agreeable to making its February filing and then begin a quarterly GCA filing schedule with a filing schedule of February, May, August, and November as long as Western has tariff provisions that permit out-of-time filings when such filings are warranted. These provisions provide the flexibility to respond to significant gas supply cost changes.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 9
Witness: Gary Smith

Data Request:

Refer to the response to Item 52 of the Commission's August 19, 1999 Order and Exhibits GLS-2 and GLS-3 of the Direct Testimony of Gary L. Smith.

a. Part (b) of the response identifies 16,113,322 Mcf as being under special contract and indicates this amount represents 57 percent of Western's total industrial sales and transportation deliveries during the test year. Identify, in Exhibits GLS-2 and GLS-3, the Mcf levels that, when summed, produce the total industrial sales and transportation deliveries that were used as the denominator to derive the result of 57 percent.

b. Refer to the response to part (a) of this request. Using the volumes included in that response, provide the amount of net revenues that would be generated under both existing rates and proposed rates and the calculations performed to derive these revenue amounts.

Response:

a. The denominator in the referenced computation is the sum of Firm Industrial Sales and Transportation, per books, 8,803,129 Mcf (Exhibit GLS-2, Column j, Line 21) plus contract adjustments, 1,603,749 Mcf (Exhibit GLS-3, Column j, Line 21), plus weather adjustments (Exhibit GLS-4, Column j, Line 21), plus Interruptible Sales and Transportation, per books, 20,399,507 Mcf (Exhibit GLS-2, Column j, Line 41) plus contract adjustments, (2,799,751) Mcf (Exhibit GLS-3, Column j, Line 41). This sum, the total industrial sales and transportation volume, is 28,049,865 Mcf.

b. Please refer to Exhibit KPSC #3 - DR Item 9(b), attached hereto, for the requested information.

WESTERN KENTUCKY GAS COMPANY
Case No. 99-070
KPSC DR Dated September 20, 1999

EXHIBIT KSPC #3
Item 9 (b)

Line No.		Per Books (Ref GLS-2)		Contr. Adj. (Ref GLS-3)		Test Year Volumes (Per Book + Acontr. Adj.)		Existing Rates		Proposed Rates	
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM INDUSTRIAL	Number Of Bills	Mcf	Number Of Bills	Mcf	Number Of Bills	Mcf	Present Margin	Present Revenues	Proposed Margin	Proposed Revenues
1	Total Firm Bills	2,770		190		2,960		13.60	40,256	24.00	71,040
2	Transport. Bills	713		296		1,009		45.00	45,405	50.00	50,450
3	Parking Fees {1}		1,780				1,780	0.10	178	0.10	178
4	Sales: 1-300 {2}		480,003		(47,225)		432,778	1.0615	459,393	1.2000	519,333
5	Sales: 301-15000 {2}		1,235,533		(403,366)		832,167	0.5585	464,766	0.6946	578,024
6	Sales: Over 15000		2,108		0		2,108	0.4085	861	0.4299	906
7	Trans: 1-300		30,455		252		30,707	1.0615	32,595	1.2000	36,848
8	Trans: 301-15000		500,929		(24,009)		476,920	0.5585	266,360	0.6946	331,269
9	Trans: Over 15000		78,311		0		78,311	0.4085	31,990	0.4299	33,666
10	LVS: 1-300		6,972		(1,500)		5,472	1.0615	5,809	1.2000	6,566
11	LVS: 301-15000		85,089		(64,563)		20,526	0.5585	11,464	0.6946	14,257
12	LVS: Over 15000		6,711		0		6,711	0.4085	2,741	0.4299	2,885
13	Carriage:1-300		168,705		104,683		273,388	1.0615	290,201	1.2000	328,066
14	Carriage:301-15000		2,680,003		672,759		3,352,762	0.5585	1,872,518	0.6946	2,328,828
15	Carriage:Over 15000		531,549		(310,532)		221,017	0.4085	90,285	0.4299	95,015
16	T-4 Overrun 1-300		11,446		(11,446)		-	1.1677	-	1.3200	-
17	T-4 Overrun 301-15,000		25,410		(25,410)		-	0.6144	-	0.7641	-
18	T-4 Overrun Over 15,000		0		0		-	0.4494	-	0.4729	-
19	Special Contracts (Confidential)		3,003,136		1,714,106		4,717,242		425,038		425,038
20	TOTAL		8,846,360		1,603,749		10,450,109		4,039,860		4,822,370
21											
22		Number Of		Number Of		Number Of		Present	Present	Proposed	Proposed
23	INTERRUPTIBLE INDUSTRIAL	Bills	Mcf	Bills	Mcf	Bills	Mcf	Margin	Revenues	Margin	Revenues
24	Total Bills	1,648		27		1,675		150.00	251,250	250.00	418,750
25	Transport. Bills	755		71		826		45.00	37,170	50.00	41,300
26	Parking Fees {1}		524,740		0		524,740	0.10	52,474	0.10	52,474
27	Alternate Receipt Point {3}									0.10	10,000
28	Interrupt Sales: 1-15000		899,934		(245,800)		654,134	0.4936	322,881	0.5300	346,691
29	Interrupt Sales: Over 15000		152,485		(127,603)		24,882	0.3436	8,549	0.3301	8,214
30	Interrupt Transport: 1-15000		786,564		(229,742)		556,822	0.4936	274,847	0.5300	295,116
31	Interrupt Transport: Over 15000		148,134		(58,376)		89,758	0.3436	30,841	0.3301	29,629
32	Interrupt LVS: 1-15000		149,567		(4,381)		145,186	0.4936	71,664	0.5300	76,949
33	Interrupt LVS: Over 15000		224,471		0		224,471	0.3436	77,128	0.3301	74,098
34	Carriage:1-15000		4,177,009		479,546		4,656,555	0.4936	2,298,476	0.5300	2,467,974
35	Carriage:Over 15000		3,493,877		(860,790)		2,633,087	0.3436	904,729	0.3301	869,182
36	T-3 Overrun 1-15,000		140,229		(140,229)		-	0.5430	-	0.5830	-
37	T-3 Overrun Over 15,000		0		0		-	0.3780	-	0.3631	-
38	Special Contracts (Confidential)		10,227,237		(1,612,376)		8,614,861		1,267,391		1,267,391
39	TOTAL		20,399,507		(2,799,751)		17,599,756		5,597,399		5,957,767
40											
41	Additional Contract Reformations {4}								(1,100,000)		(1,184,884)
42											
43	TOTAL Industrial		29,245,867		(1,196,002)		28,049,865		8,537,260		9,595,253
44											

45 {1} - Parked Volumes not included in Total Deliveries.
46 {2} - Column b includes corresponding weather adjustment volumes from Exhibit GLS-4.
47 {3} - Alternate Receipt Point proposed revenues based on 100,000 Mcf.
48 {4} - Discount from current rates (Column h); Discount from proposed rates (Column j). Based on Confidential Information.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 10
Witness: Gary Smith

Data Request:

Refer to the response to Item 53 of the Commission's August 19, 1999 Order.

a. Identify the periods that were covered by the field arrears reports that were reviewed.

b. If implemented as proposed, the Late Payment Charge would be effective April 1, 2000 and would remain in effect permanently on a going forward basis. Explain why Western believes it is appropriate to include only nine months of Late Payment Charge revenues in the forecasted test year.

Response:

Given the content of sub-parts (a) and (b) of this DR Item, I believe the intended reference in the Commission's August 19, 1999 Order is to Item 54 instead of Item 53.

a. Information from field arrears reports was gathered for the five months of October 1998 through February 1999.

b. Western's inclusion of nine months of revenue for the Late Payment Charge in the forecasted test year is consistent with Company's plans for implementation of this charge. The forecasted test year in this case is the Calendar Year of 2000, and the estimated revenues attributable to the proposed Late Payment Charge are appropriately represented for the stated period.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 11 (a)
Witness: Gary Smith

Data Request:

Refer to the response to Item 55 (d) of the Commission's August 19, 1999 Order.

a. Provide the basis for the allocation of new connections of 1,700 between "Main and MSR" and "MSR Only".

Response:

Given the content of sub-part (a) of this DR Item, I believe the intended reference in the Commission's August 19, 1999 Order is to Item 55 (e) instead of Item 55 (d).

a. Western provided the referenced information to Mr. Ives for purposes of his analyses. The Company's estimate for residential growth of 1,700 customers per year may be found referencing the testimony of Mr. Smith, at Volume 2 of 10, Tab 11, page 11, line 19 through page 12, line 26. Based upon trends observed in the Company's marketing reports, Western estimated the components of the net residential growth to be: 1,450 - residential new construction (requiring a main extension, or "Main and MSR"), and 250 - on-main residential conversions ("MSR Only). Please also reference the Company's response to KPSC DR 1 - Item 58 (d), KPSC DR 2 - Item 45 (b), and AG DR 1 - Item 36 (a, b).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 11 (b)
Witness: Gary Smith

Data Request:

Refer to the response to Item 55 (d) of the Commission's August 19, 1999 Order.

b. Would the allocation ratio between "Main and MSR" and "MSR Only" remain the same if the number of connections were an amount larger or smaller than the 1,700 used in the calculation? If no, explain why it would be different.

Response:

Given the content of sub-part (b) of this DR Item, I believe the intended reference in the Commission's August 19, 1999 Order is to Item 55 (e) instead of Item 55 (d).

b. The split between "Main and MSR" and "MSR Only" residential customer additions was not made on a percentage allocation basis, but rather on an estimate of the number of customer hook-ups by type (see response to part a. of this DR Item). The Company believes that the number of conversions ("MSR Only") available is quite limited (reference the testimony of Mr. Smith, at Volume 2 of 10, Tab 11, page 12, lines 14-18). Therefore, positive or negative variances from the Company's overall growth estimate of 1,700 residential customers would most likely be attributable to changes in new construction markets - residential additions requiring "Main and MSR".

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request No. 3
DR Item 11 (c)
Witness: Daniel M. Ives

Data Request:

11. Refer to the response to Item 55(d) of the Commission's August 19, 1999 Order.

c. The "Number of Customers – 2001" reflects additions of 1,700 for each of the calendar years 1999 and 2000 to the customer count as of September 30, 1998. Explain why no customer additions were reflected for the last three months of calendar year 1998.

Response:

11(c) The company's response to Item 55 (d) of the Commission's August 19, 1999 Order contains no such information "Number of Customers – 2001."

Footnote 4 of the attachment to the company's response to Item 55 (e) of the Commission's August 19, 1999 Order did contain the cited reference. In that response, the estimated number of residential customers as of January 1, 2001 was derived by adding estimated customer additions of 1700 per year for fiscal 1999 and fiscal 2000 to the 9/30/98 average customer base of 151,820. No adjustment was made for estimated customer additions in the months of October – December 2000.

As noted on Exhibit DMI-6, Schedule 2, footnote 2, for purposes of Premises Charge calculation customer additions are assumed to connect ratably over the non-winter months of April through October. For purposes of calculation of a Facilities Adjustment Charge of $15.44 per year for all residential customers, the estimated customer additions for October 2000 were disregarded. However, as noted below, addition of October customer additions would only change the annual amount of the Facilities Adjustment Charge by $.03 per customer.

Response, continued:

11 (c): Recalculation of the alternate proposal, a Facilities Adjustment Charge, including an estimate of 242 customer additions for October 2000, would lower the estimated charge from $15.44 per year per residential customer to $15.41 per year, or $ 1.28 per month, as reflected on the attached schedule. As noted in Witness Ives direct testimony at page 18, lines 18-19, the amount of such proposed alternate charge "could be adjusted annually for cost changes and the number of customer additions." Further, Mr. Ives' testimony states that accounting and reporting requirements would be similar to those proposed for the Premises Charge.

Western Kentucky Gas Company
Response to Data Request No. 3
Public Service Commission of Kentucky
Question No. 11 (C)

If the Commission elects to implement the alternative "Facilities Adjustment Charge," it may be computed by estimating the annual amount of Excess Investment associated with new Residential hook-ups that require main extension and a Meter, Service Line and Regulator (MSR), and the annual amount of Excess Investment associated with new Residential hook-ups that require MSR only. The combined annual Excess Investment is grossed-up for Federal and State taxes and then divided by the estimated number of Residential customers in 2001 to produce the annual cost per Residential customer of $15.41, as illustrated below:

Excess Investment	Amount Excess Investment 1/	Budgeted Annual No. of Connections 2/	Total
Main and MSR	$858	1450	$1,244,100
MSR Only	$740	250	$185,000
		1700	$1,429,100
Tax Gross-up Factor (.5964) 3/			
Annual Excess Investment - Grossed-up for Taxes			$2,396,211
Number of Customers - 2001 4/			155462
Annual Cost (incl. Tax) /All Residential Customers			$15.41
Rolled-in Monthly Cost For All Residential Customers			$1.28

No carrying charges are imputed as recoveries and expenditures are assumed to occur ratably.

1/ Refer to Exhibit DMI-5, Schedule 1 for Excess Investment.
2/ Refer to Exhibit DMI-6, Schedule 1 for budgeted number of New Residential Customers.
3/ Refer to Exhibit DMI 5, Schedule 2 for tax factor.
4/ Residential Customers 9/30/98 151820 (Exhibit DMI 2, Schedule 2)

4/ Residential Customers 9/30/98	151820	(Exhibit DMI 2, Schedule 2)
1999 Additions	1700	(Exhibit DMI-6, Schedule 1)
2000 Additions	1700	(Exhibit DMI-6, Schedule 1)
	155220	
OCT. 2000 ESTIMTED ADDITIONS (208+34) 5/	242	
	155462	

5/ CUSTOMER ADDITIONS FOR OCTOBER ESTIMATED AT 208 FOR NEW MAIN/MSR HOOK-UPS AND 34 FOR MSR ONLY HOOK-UPS, AS REFLECTED ON EXHIBIT DMI-6, SCHEDULES 2 AND 3.

Notes

12

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 12
Witness: Doggette

Data Request:

Refer to the response to Item 56 of the Commission's August 19, 1999 Order. Historically, Commission approval of returned check charges has required cost support on a utility-by-utility basis. The intent of such charges is to charge the costs incurred by the utility to process the bad check to the cost-causer rather than to the entire body of ratepayers. Provide the cost calculations necessary to support a returned check charge based on Western-specific costs.

Response:

The goal of Western's local market survey, Refer to KPSC Data Request #2, DR Item 56 a-d, was not to determine the actual level of costs incurred but to determine the general level of returned check charges being utilized to affect customer behavior. Western has identified the full cycle costs associated with the returned check charge. The costs identified below are costs incurred to process a returned check and to roll a service truck for disconnection of service or to leave a "door tag". The full cycle charges are as follows:

Bank return check fee	$2.75	Bank check fee
Bank auto-present fee	$2.25	Bank check fee
Labor & supervision	$4.30	($51.92/hr)/(12 chks/hr) incl. benefits & OH
Delinquent/Termination notice	$0.34	Cost per bill insert item
Customer Support Center	$2.53	Exhibit DHD-2, page 1of 8, Col. 10
Service Technician	$9.46	Exhibit DHD-2, page 1of8, line 3, Col. 9
Total	**$21.63**	

Notes

13

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request No. 3
DR Item 13
Witness: Ives

Data Request:

13. Refer to lines 22 through 24 on page 4 of the Direct Testimony of Earl Fischer.

Describe how Western's return on new investments compare with those of Atmos' other business units.

Response:

13. Western's return on new investments has lagged behind Atmos Energy's other business units for commercial projects and for residential projects. Samples of 1994-1997 projects for Western Kentucky revealed average returns on equity of -8.7% for commercial and -14.8% for residential projects, compared with Greeley Gas' returns on equity of 10.09% for commercial and -8.9% for residential projects for sampled 1995-1997 jobs. Energas' average return on equity for 1994-1997 sampled projects was 19.0% for commercial projects and -10.8% for residential projects.

Western's proposed Premises Charge is the primary tool the company is proposing in this rate case to help ameliorate its earnings deficit on new projects.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-14.a
Witness: Donald A. Murry

Data Request:

3-14. Refer to pages 19 and 20 of the Direct Testimony of Dr. Donald Murry, to Schedules DAM–16 and DAM-17, and to Items 32 and 33 of the response to the Commission's August 19, 1999 Order.

a. Reconcile the response in Item 32(c) with the description of Schedule DAM-16 that begins at line 18 on page 19 of the testimony.

Response:

a. The discussion of the CAPM methodology, which is a risk premium method, at lines 18 and 19 on page 20 refers to the usual description of the technique. For example, the common expression describing the CAPM method is stated and explained at lines 14-19 of page 18. Note in this expression the "risk-free rate" is a constant, as is the beta. However, the risk differential is a variable which is the difference between the "risk-free rate" and the "market return." In practice, the selected constant or "risk-free rate" will also alter the differential between the "risk-free" rate and the market return. Dr. Murry applied this theoretical model in Schedule 16 using the long-term corporate bond rate , which is an historical rate, as the constant. For a discussion concerning the use of different constants, which are referred to in the explanation of the theory as "risk-free" rates, please see the response to Staff Data Request 3-14.d.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-14.b
Witness: Donald A. Murry

Data Request:

3-14.b. Fully describe, compare, and contrast the CAPM methodologies employed in Schedules DAM-16 and DAM-17. Include a more thorough explanation of the responses given in Items 32(e) and 33(d), as well as a full description of each variable used in each equation, its specific source, the time period covered by each variable, and its purpose in the specific equation that it is used.

Response:

b. For a detailed explanation of the variables, a description of the variables, the duration of any time series and the purpose of choosing a variable in the analysis shown on Schedule DAM-16, please see the following table.

Explanation of Data in Schedule DAM-16				
Variable	Description	Source	Time Period	Purpose
Market Total Returns	Please see response to AG1-12	*Ibbotson Associates SBBI 1999 Yearbook*, Table 6-7, p. 122	1926 to 1998	To serve as a proxy of the return on equity for the market as a whole
Long-Term Corporate Bonds Return	Historical total return for long term corporate bonds of investment grade	*Ibbotson Associates SBBI 1999 Yearbook*, Table 6-7, p. 122	1926 to 1998	To serve as a proxy of the historical risk free rate
Risk Premium	Market Total Returns minus Long-Term Corporate Bonds Return	N/A	N/A	N/A
Beta	A measure of the relative risk of a given security to the market as a whole	*Value Line Investment Survey*	1995 to 1999	To serve as a proxy for the given security's beta coefficient in the CAPM equation
Adjusted Risk Premium	Risk Premium multiplied by Beta	N/A	N/A	N/A
Aaa Corporate Bonds Return	The current yield on Moody's Aaa corporate bonds	*Federal Reserve Statistical Release*	March 1999	To serve as a proxy for the current risk free rate

For a detailed explanation of the variables, a description of each variable, the duration of any time series and the purpose of choosing this variable in the analysis shown on Schedule DAM-17, please see the following table. Please observe that the two techniques in these schedules differ by data source and period which accounts for differing approaches to estimate a current cost of common stock equity.

Explanation of Data in Schedule DAM-17				
Variable	Description	Source	Time Period	Purpose
Risk Free Return	The composite over 10 years (long- term) yield on U.S. Treasury bonds	*Federal Reserve Statistical Release*	March 1999	To serve as a proxy for the current risk free rate
Beta	A measure of the relative risk of a given security to the market as a whole	*Value Line Investment Survey*	1995 to 1999	To serve as a proxy for the given security's beta coefficient in the CAPM equation
Equity Risk Premium	The risk associated with holding stocks above the risk free yield	*Ibbotson Associates SBBI 1999 Yearbook*, Table 8-1, p. 164	1926 to 1998	To represent the historical risk associated with the S&P 500
Adjusted Equity Risk Premium	Equity Risk Premium multiplied times Beta	N/A	N/A	N/A
Size Premium	A risk adjustment to account for the relative size of a given company	*Ibbotson Associates SBBI 1999 Yearbook*, Table 8-1, p. 164	1926 to 1998	To serve as an adjustment due to the risk associated with smaller equities
Cost of Equity	Risk Free Return plus Adjusted Equity Risk Premium plus Size Premium	N/A	N/A	The estimated cost of equity for the given company

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-14.c
Witness: Donald A. Murry

Data Request:

3-14.c. If not fully explained in part (b) above, explain why the simple extension of the standard CAPM methodology to account for company size necessitates the use of different input values for those inputs that are common to both sets of calculations in Schedules DAM-16 and DAM-17.

Response:

c. The use of the same data as input variables in the calculations in Schedules DAM-16 and DAM-17 would be inappropriate because the method of estimating the cost of capital based on the CAPM theory in the two schedules differs. The risk premium used in Schedule DAM-17 is based on a "long-horizon" differential between large company stock returns and long-term government bonds, and the risk premium in Schedule DAM-16 is based, in part, on current market returns. There are structural differences requiring a choice of other input variables. For example, Schedule DAM-16 applied a global adjustment to account for the size bias associated with the CAPM analysis and the data selected for the analysis. Schedule DAM-17 used a CAPM method that provides for a specific adjustment to each measure of the cost of common stock equity based on the market capitalization. (Please refer to description of the "Purpose" of each variable set forth in Staff Data Request 3-14.b).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-14.d
Witness: Donald A. Murry

Data Request:

3-14.d.Provide copies of the relevant sections from academic texts, such as Morin's Regulatory Finance, which justify the use of different input values in place of the same inputs used in similar calculations when the time periods used in the calculations do not change.

Response:

d. Each input value has its empirical shortcomings which require analysts to isolate and compensate for its effects. For example, some academic analysts have suggested the use of a long-term government bond yield or an AA industrial bond rate as the risk-free rate in a CAPM analysis. Dr. Murry applied both to produce a range for the CAPM return on equity estimate. Please see the response to KPSC 3-14.b above. Please see attached quotation from Roger Morin's *Regulatory Finance,* pp. 308-309. In this citation please note that Morin quotes D. R.. Harrington , in *Modern Portfolio Theory, The Capital Asset Pricing Model, and Arbitrage Pricing Theory: A User's Guide,* 1987. Harrington notes the debate among analysts regarding the selection of a "risk-free rate" for use in practice. Harrington observes that some analysts believe that the monetary policy of the Federal Reserve, by altering the level of the U. S. Treasury Bill rate, renders the T-Bill rate less desirable than others as the risk-free rate in a CAPM analysis. For example, Harrington states that "...many practitioners suggest the use of a long-term government rate or an AA industrial bond rate as a proxy for a risk-free rate."

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with
Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

Harrington (1987) took an even more practical approach in estimating the risk-free rate. Unlike most theoretical textbooks, Harrington suggests looking at this from the point of view of a practitioner who has a real problem:

> Because of the empirical evidence, the intercept is consistently higher than a Treasury security and the fact that a Treasury bill rate is heavily influenced by Federal Reserve activity and is thus not a free-market rate, many practitioners suggest the use of a long-term government rate or an AA industrial bond rate as a proxy for the risk-free rate .... Because U.S. Treasury bills are usually considered the closest available approximation to a risk-free investment, the discount rate on Treasury bills is often used as a risk-free rate. This creates some very serious problems, however, because the rate of Treasury bills like that on most short-term marketable instruments is quite volatile. One way to approach the problem of dealing with the risk premium factor is to use the long-term interest rate instead of the risk-free rate....The most widely used proxies, 30 or 90-day Treasury bill rates, are empirically inadequate and theoretically suspect.[4]

While the spot yield on long-term Treasury bonds provides a reasonable proxy for the risk-free rate, the CAPM specifically requires the expected spot yield. Market forecasts of rates on Treasury bonds are available in the form of interest rate futures contract yields, and can be employed as proxies for the expected yields on Treasury securities.

Over the last 50 years, the Treasury bill rate has approximately equaled the annual inflation rate, as demonstrated in Fama (1975) and Ibbotson Associates (1993). Refined techniques to forecast inflation based on the current shape of the yield curve could thus be employed to obtain the expected risk-free rate.[5] Alternately, the consensus inflation forecast by economists over the requisite horizon could be employed to derive the risk-free rate estimate. However, none of these techniques is likely to provide superior estimates to that supplied by current yield data. The complexity and computational costs are likely to outweigh their marginal usefulness.

In practice, sensitivity analyses employing various input values for the risk-free rate can produce a reasonably good range of estimates of equity costs. For example, for a risk-free rate range of 7% to 8% and a market

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4 See Harrington (1987).

5 See Ibbotson and Sinquefield (1982) for a description of the methodology of forecasting future security yields based on yield curve analysis.

where $E(K)$ = expected return, or cost of capital

$E(R_F)$ = expected risk-free rate

$E(\beta)$ = expected beta

$E(R_M)$ = expected market return

The difficulty is that the CAPM model is a prospective model while most of the available capital market data required to match the three theoretical input variables (expected risk-free return, expected beta, and expected market return) are historical. None of the input variables exists as a separate identifiable entity. It is thus necessary in practice to employ different proxies, with different results obtained with each set of proxy variables. Each of the three required inputs to the CAPM is examined below.

Risk-free Rate

Theoretically, the yield on 90-day Treasury bills is virtually devoid of default risk and subject to a negligible amount of interest rate risk. But, as seen in the previous chapter, the T-bill rate fluctuates widely, leading to volatile and unreliable equity return estimates, and it does not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days. More importantly, short-term Treasury bill yields reflect the impact of factors different from those influencing long-term securities, such as common stock. For example, the premium for expected inflation absorbed into 90-day Treasury bills is likely to be far different than the inflationary premium absorbed into long-term securities yields. The yields on long-term Treasury bonds match more closely with common stock returns. For investors with a long time horizon, a long-term government bond is almost risk-free.

In their well-known corporate finance textbook, Brigham and Gapenski (1991) stated the following:[3]

> Treasury bill rates are subject to more random disturbances than are Treasury bond rates. For example, bills are used by the Federal Reserve System to control the money supply, and bills are also used by foreign governments, firms, and individuals as a temporary safe-house for money. Thus, if the Fed decides to stimulate the economy, it drives down the bill rate, and the same thing happens if trouble erupts somewhere in the world and money flows into the United States seeking a temporary haven.

[3] See Brigham and Gapenski (1991).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-14.e
Witness: Donald A. Murry

Data Request:

3-14.e. Provide all the calculations and results of any sensitivity analysis that Western has conducted supporting the CAPM calculations in Schedules DAM-16 and DAM-17. For each variable whose input value was changed from one set of calculations to the other, explain the rationale behind the range of input values used.

Response:

e. Because Dr. Murry chose the variable to represent the best estimate using the different methodologies in DAM-16 and DAM-17 a sensitivity analysis of input variables was inappropriate. Instead, the chose of alternative methods demonstrates the sensitivity of the CAPM analysis to historical data and to current data

As pointed out in responses 32(e) and 33(d), Schedules DAM-16 and DAM-17 represent two different methods to estimate the cost of capital using the formal CAPM theory. For example, the company size bias results from the use of an historical equity risk premium in the calculation depicted in Schedule DAM-17, and consequently, a company size adjustment in the calculation in that schedule is appropriate. In the case of Schedule DAM-16, in calculating the risk premium, there is an estimate of current market returns. Dr. Murry used this method in part, to avoid the need to adjust for the size bias in the Ibbotson Associates' data.

Notes

15

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-15
Witness: Donald A. Murry

Data Request:

3-15. Refer to the response to Item 12 of the Attorney General's ("AG") Data Request of August 19, 1999. The page provided from Ibbotson Associates SBBI 1999 Yearbook includes government as well as corporate bond Total Return rates. Explain why a government bond rate was not used as the risk-free rate in the CAPM calculation in Schedule DAM-16.

Response:

15. The long-term government bond rate is not a rate without any risk to investors; in that sense, it is not a "risk-free" rate. There is risk to an investor in an investment in government bonds. Analysts have used and continue to use a number of base rates for the constant, or "risk-free rate," in applying the CAPM method. The long-term government bond rate and the corporate bond rate have different risks and the differential in risk between each of these securities and the market rate varies overtime. There are, nevertheless, some analytical benefits from using the current corporate bond rate as the constant in estimating the cost of capital with a CAPM method. For example, for purposes of estimating the current cost of capital, there is a likelihood that some of the current risks of a particular corporate common stock are likely to be reflected in the current corporate bond market. (Please see the response to Staff Data Requests 3-14.a and 3-14.d)

Notes

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-16.a
Witness: Donald A. Murry

Data Request:

3-16. Refer to the response to Item 9 of the AG's Data Request of August 19, 1999.

a. Table 8-1 of the SBBI 1999 Yearbook sets out the Equity Risk Premium and the Size Premia used in Schedule DAM-17 of Dr. Murry's testimony. Explain why the risk-free rate was not taken from Table 8-1 as well.

Response:

a Please see the discussion of the difference between Schedules DAM-16 and DAM-17 in Staff Data Request 3-14.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-16.b
Witness: Donald A. Murry

Data Request:

3-16.b. Were the size premia set out in Table 8-1 developed from utility stock returns? If not, identify which companies' returns were used and explain how those returns are applicable to gas utilities.

Response:

b. The premia were developed from the returns of all stocks in portfolios developed by the Center for Research in Security Prices at the University of Chicago's Graduate School of Business. Utilities' securities are among the securities included in the calculation of the premia used to compensate for the size bias in the CAPM. Consequently, the size adjustment applies to common equities that include gas utilities. Please see *Ibbotson Associates SBBI 1999* Yearbook, p. 127.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-16.c
Witness: Donald A. Murry

Data Request:

3-16.c. Provide a detailed explanation of how the size premia set out in Table 8-1 are calculated.

Response:

c. For a complete explanation, please see *Ibbotson Associates SBBI 1999 Yearbook*, p. 127-143.

Notes

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State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-17
Witness: Donald A. Murry

Data Request:

3-17. If Morin's Regulatory Finance, which is mentioned in response to Item 13 of the AG's Data Request of August 19, 1999, contains a discussion of the use of size premia for utilities, provide a copy of that discussion.

Response:

3-17. Please see the attached discussion in Morin's *Regulatory Finance.* Please note that he devotes a section of the chapter on CAPM to the "Size Effects" in which he notes, at page 329, the "...investment risk increases as company size diminishes...."

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with

Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

FIGURE 13-4C

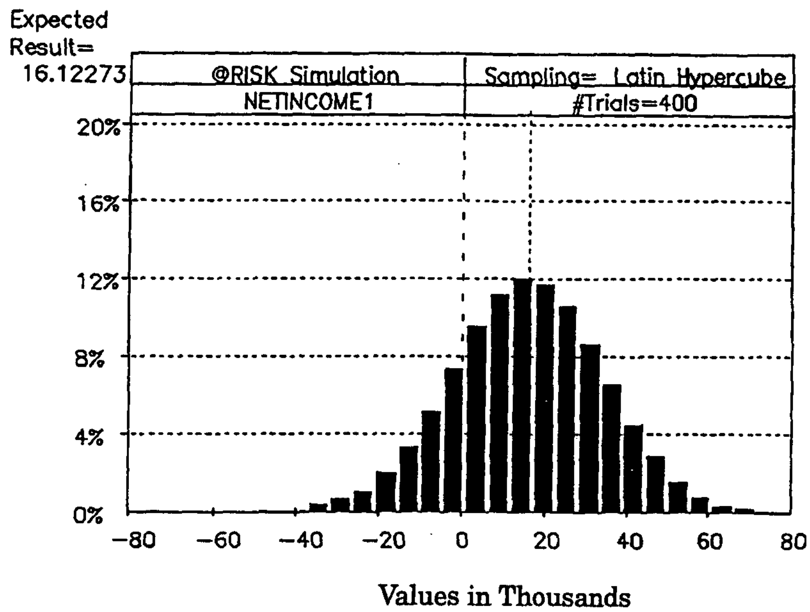


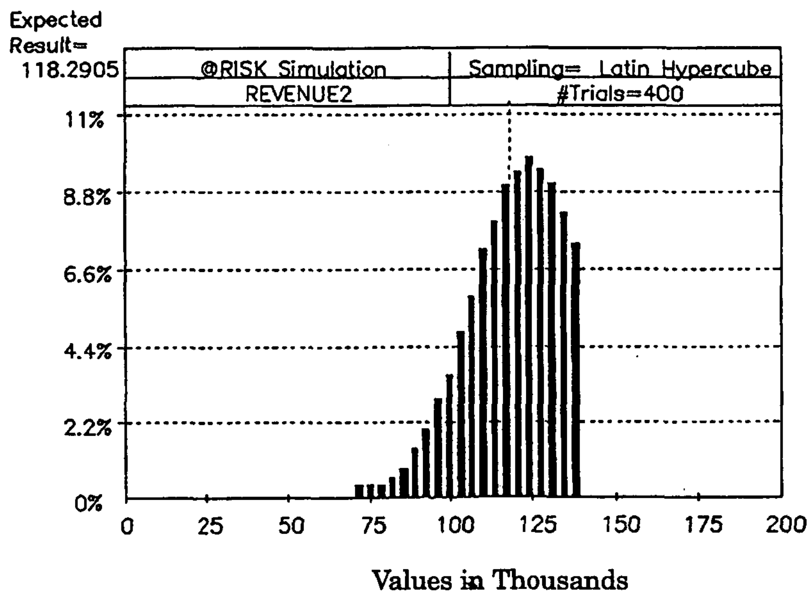
Figure 13-5 shows the same probability distributions if revenues are negatively skewed. Note the increased downside net income potential and, hence, the increased risk. The coefficient of variation of revenue, EBIT, and net income become 0.12, 0.43, and 1.41, respectively. The risk to the shareholder increases from 1.11 to 1.41 as a result of leverage and skewness effects.

This result reinforces that notion that an added premium is required to offset the lack of upside potential. The added premium must be sufficient to produce the same average return that would prevail under conditions of perfect symmetry.

Size Effects

Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Empirical studies by Banz (1981) and Reinganum (1981A) have found that investors in small-capitalization stocks require higher returns than predicted by the standard CAPM. Reinganum (1981A) examined the relationship between the size of the firm and its P/E ratio, and found that small firms experienced average returns greater than those of large firms that were of equivalent systematic risk (beta). He found that small firms produce greater returns than could be explained by their risks. These results were confirmed in a separate test by Banz (1981) who examined stock returns

FIGURE 13-5A
HYPOTHETICAL PROBABILITY DISTRIBUTIONS:
NEGATIVELY SKEWED REVENUES



over the much longer 1936-1975 period, finding that stocks of small firms earned higher risk-adjusted abnormal returns than those of large firms.

Small companies have very different returns than large ones, and on average they have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. Ibbotson Associates' widely-used annual historical return series publication covering the period 1926 to the present reinforces this evidence (Ibbotson Associates, 1993). They found that for the period 1926-1992 the average small stock premium was 6% over the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. One plausible explanation for the size effect is the higher information search costs incurred by investors for small companies relative to large companies. This effect is likely to be negligible for all but the very small public utilities whose equity market value is less than $60 million.

In addition to earning the highest average rates of return, the small stocks also had the highest volatility, as measured by the standard deviation of returns. Ibbotson defines small stocks as those in the lowest size decile among NYSE stocks, with size defined as the dollar value of shares outstanding. The size trigger point occurs at a market value of $60 million.

FIGURE 13-5B

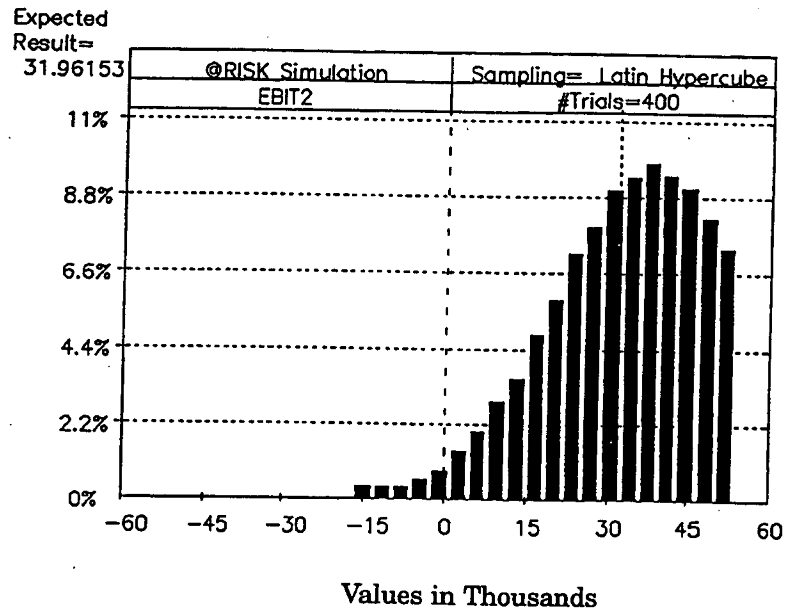
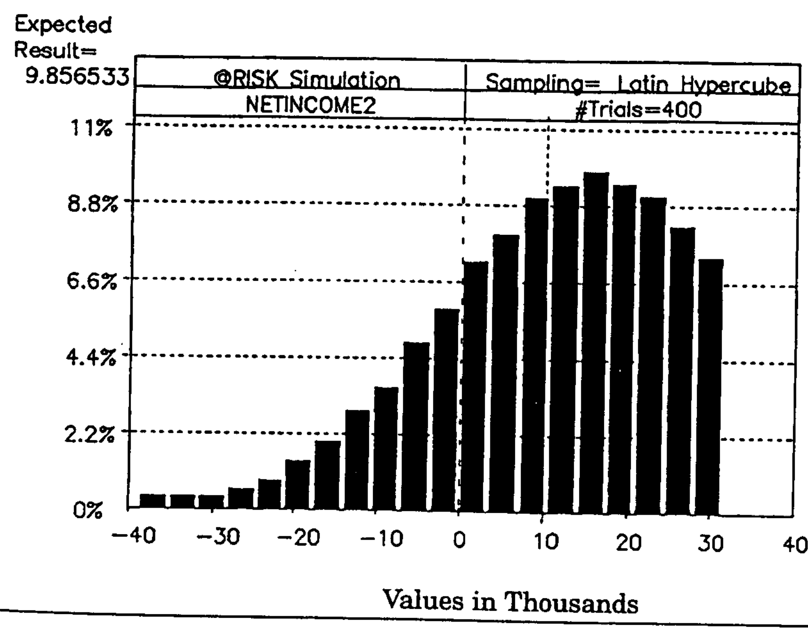


FIGURE 13-5C



The bond ratings of small firms are typically less than those of large firms. Figure 13-6 contrasts the Standard & Poor's bond and stock ratings of small versus large capitalization stocks. For bond ratings, the first quintile of companies ranked in descending order of market value of equity is ranked A- on average, versus CC for the last quintile. For stock ratings, the first quintile of companies is ranked A- to B+, versus C for the last quintile.

FIGURE 13-6A
STANDARD & POOR'S AVERAGE BOND RATING: TOP 20% AND BOTTOM 20% OF MARKET
(Compustat Data Base Ranked by Market Value)

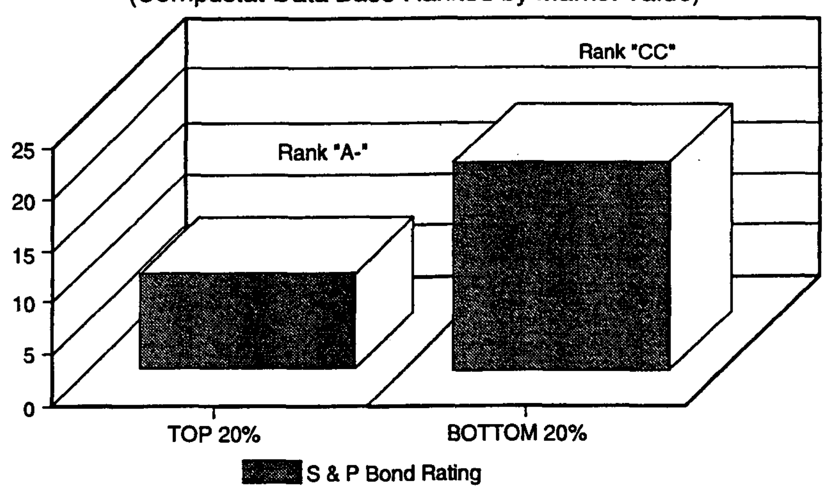
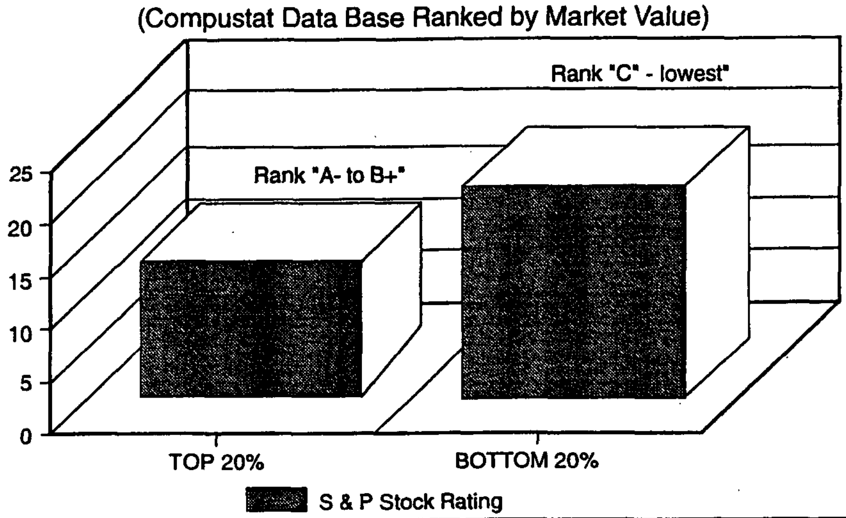


FIGURE 13-6B
STANDARD & POOR'S AVERAGE STOCK RATING: TOP 20% AND BOTTOM 20% OF MARKET
(Compustat Data Base Ranked by Market Value)



Much research effort has gone into investigating the size effect. In addition to statistical measurement problems, the economic rationale for the size effect is difficult to unravel. In fact, Roll (1981) even questioned the evidence on the small firm effect. Presumably, small stocks provided less utility to the investor, and require a higher return. The size effect may be a statistical mirage, whereby size is proxying for the effect of different economic variables. Small firms may have low price-earnings ratios or low market prices, for example. The size effect is most likely the result of a liquidity premium, whereby investors in small stocks demand greater returns as compensation for lack of marketability and liquidity. Investors prefer high to low liquidity, and demand higher returns from less liquid investments, holding other factors constant.

Market Index and Missing Assets

A second explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index misspecifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) provide an illustration of the biases in beta estimates that result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relationship between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Constraints on Investor Borrowing

The third explanation for the CAPM's deficiency involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

Notes

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-18.a
Witness: Donald A. Murry

Data Request:

3-18.a.Refer to Schedules DAM-18 and DAM-19 of Dr. Murry's Testimony.

a. The Dow Jones Utilities' price appreciation does not deviate from those of the Dow Jones Industrials and Moody's Transmission companies to the extent that Moody's LDCs do, and in fact, for a period of time it exceeds them. To the extent that competition and deregulation are increasing in the majority of utility industries, provide Dr. Murry's assessment of the shift in risk for the utility industry as a whole as perceived by investors.

Response:

a. Deregulation and increased competition is common throughout the utility industries, but the effect of deregulation and the emergence of competition differs from industry to industry and within an industry from sector to sector. For example, the gas transmission sector is now more competitive generally than the gas distribution sector, and there are areas of the gas distribution sector that will never achieve the level of competitive interaction that exists throughout much of the transmission sector today. Several of the Moody's Gas Transmission Companies are also included in the Dow Jones Utilities Index (Please see the table below). Therefore, it is not surprising that the indices of the two are often similar. The LDC sector however, is not well represented in the Dow Jones Utilities Index. Moreover, a significant difference between the gas distribution sector and the other utilities is the status of emerging competition and the effects of residual regulatory risk perceived by investors. (Please see, for example, the response to AG #1-DR 15).

b. 3-18.a Page 2

Dow Jones Utilities Index Companies	Moody's Gas Transmission Companies
American Electric Power Columbia Energy Consolidated Edison Consolidated Natural Gas Duke Energy Edison International Enron Capital PECO Energy PG & E Energy Public Service Enterprises Reliant Energy The Southern Company Texas Utilities Unicom The Williams Companies	Coastal Corporation Duke Energy Enron Capital Sonat, Incorporated The Williams Companies

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-18.b
Witness: Donald A. Murry

Data Request:

3-18.b. The Atmos price appreciation does not deviate from the Dow Jones Industrials and Moody's Transmission companies to the extent that Moody's LDCs do, and in fact, for periods of time it exceeds them. Provide Dr. Murry's assessment of investors' perceived shift in risk due to deregulation and increasing competition for Atmos relative to Moody's LDCs.

Response:

b. The predicate, or preliminary statement, in the question is an inaccurate depiction of Atmos' stock performance over the past few months. In the data analyzed, Atmos has lost 25% of its market value since the beginning of the year 1999 while the Dow Jones Industrials have increased 10% in value. Generally, investors probably perceive a shift in risk due to deregulation and increasing competition for Atmos and the Moody's LDCs that is somewhat similar. Of course, there are risks to investors in individual companies such as risks associated with markets, costs of operation, weather and regulatory treatment, that will differ from the risks of LDCs as a group.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-18.c
Witness: Donald A. Murry

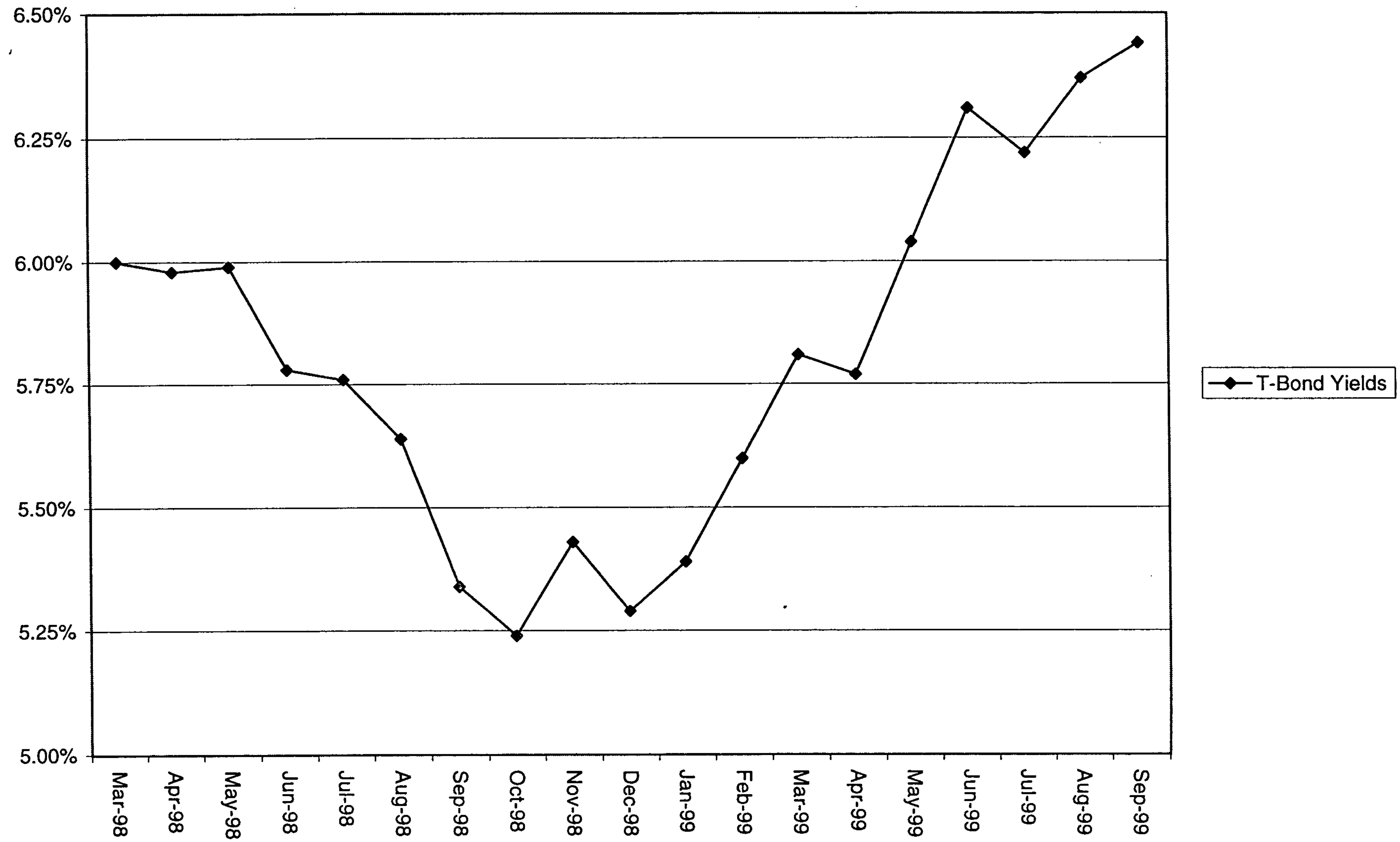
Data Request:

3-18.c. To what would Dr. Murry attribute the sudden stock price depreciation for Atmos, the Moody's LDCs, and the Dow Jones Utilities beginning in December 1998?

Response:

c. Although the reasons for the stock movements of Atmos' stock prices, the Moody's LDCs stock prices and the Dow Jones Utilities index, are not apparent, the stock price depreciation beginning at the end of 1998 is probably caused, at least in part, by the shift in interest rates that occurred at the same time. (Please see the attached graph of interest rates). Although many utilities are in increasingly competitive markets, many are not and it is likely that the value of common stocks of many utilities remain sensitive to the level of interest rates.

Yields of 10-Year Composite Treasury Bonds



Notes

19

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-19.a
Witness: Donald A. Murry

Data Request:

3-19 Refer to the response to Item 16 of the AG's Data Request of August 19, 1999. The studies and articles provided in the response to Item 16, which questioned how the financial markets assess the shift of risk between interstate transmission companies and LDCs, were published between 1993 and 1996. Schedule DAM-18, which supports Dr. Murry's testimony that investors are able to distinguish between the risks and returns of gas distribution and transmission companies, depicts price appreciation for Dow Jones Industrials, Moody's Transmission companies, and Moody's LDCs for March 1998 through March 1999. Page 20 of Dr. Murry's Testimony discusses investors' assessment of changing risks for LDCs brought about by deregulation of pipelines and increasing competition.

a. Explain why Dr. Murry assumes that the relatively lower price appreciation of LDC stocks for March 1998 through March 1999 is a result of the pipeline deregulation and emerging competition discussed in the studies published during the period 1993-1996.

Response:

a. The stock values of the gas distribution and transmission companies diverged during the period when Federal Energy Regulatory Commission's Orders 436 and 636 were a topic of discussion by financial analysts, and this illustrates the awareness of the distinction between the two sectors at that time. (As an illustration of the divergence of the prices of gas distribution companies and gas transmission companies, please see the attached Schedule from Dr. Murry's testimony in Nashville Gas Company Before the Tennessee Public Service Commission, April 29, 1994). The effects of deregulation of the gas transmission industry, as noted by the studies cited in the question, are evidence that analysts placed value upon successful deregulation. With the active merger, acquisition and entry into new businesses by the former interstate gas pipelines, there is evidence that investors are able to distinguish between the gas transmission and gas distribution sectors. Many investors are aware of these differences and the differences in regulation in the two sectors. Please see the response to Staff Data Requests 3-18.a. and 3-18.c.

Tennessee Public Service Commission
Docket No. ________

Direct Testimony of Donald A. Murry
on Behalf of
Nashville Gas Company,
a Division of
Piedmont Natural Gas Company, Inc.

April 29, 1994

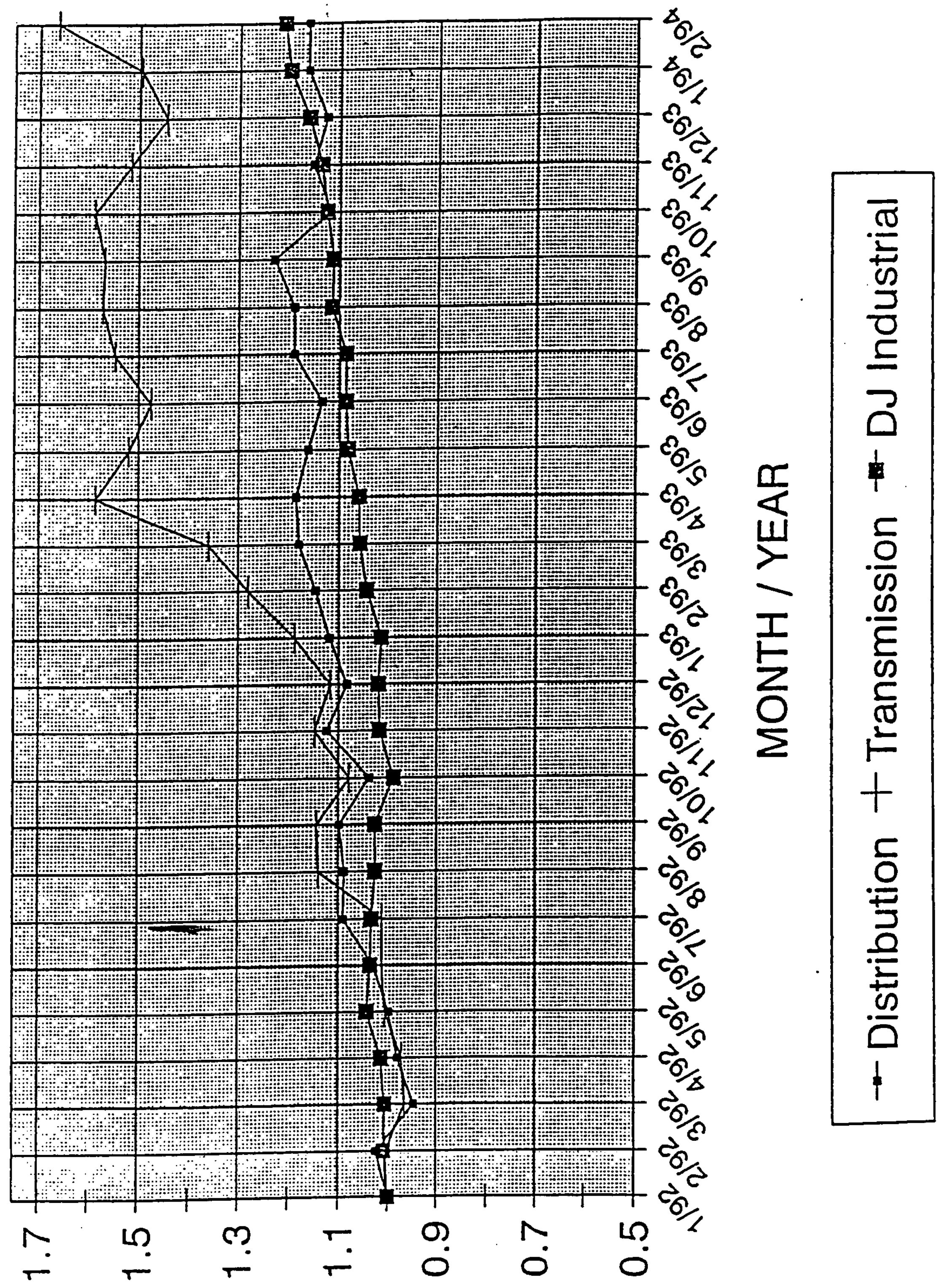
Piedmont
Natural Gas
Company

Nashville Gas
Company

EXHIBIT__(DAM-1)

SCHEDULE 16

COMPARISON OF STOCK PRICE INDICES



State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-19.b
Witness: Donald A. Murry

Data Request:

3-19.b. Could LDC price appreciation be impacted by the warmer than normal weather experienced during March 1998 through March 1999? Explain the answer in detail.

Response:

b. For short-term investors, weather conditions that differ from long-term patterns affect reported earnings, and warmer weather than normal is likely to cause some short-term price effects. However, weather in any single year is unlikely to affect the investment decisions of long-term investors.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-19.c
Witness: Donald A. Murry

Data Request:

3-19.c. Would investors assess transmission companies, with their Straight Fixed Variable rate design, to be as risky as LDCs during a warmer than normal winter? Explain the answer in detail.

Response:

c. No. Straight Fixed Variable (SFV) rate design is a means for allocating capacity costs between firm and interruptible service, and it compensates for the risk impact of variable loads on the recovery of costs through firm and variable rates. However, even weather sensitive rates will not recover the capacity costs allocated to interruptible rates, and LDCs will still have the risk of recovering those costs in a warmer than normal winter. Furthermore, there are more sources of the risk differentials between LDCs and transmission than the short-term effects resulting from differentials in the rate design. Please see the answers to 3-19.a. and 3-19.b.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-19.d
Witness: Donald A. Murry

Data Request:

3-19.d. Would investors assess the Dow Jones Industrials to be as risky as LDCs during a warmer than normal winter? Explain the answer in detail.

Response:

d. Dr. Murry is not aware of any analysts or writers who have recommended that investors choose industrial stocks because of the short-term effects of weather upon gas distribution companies' earnings. Because weather variability is a factor that investors consider, long-term investors will account for this risk, in part, at the time of their investment. The other factors that distinguish an industrial company from an LDC, however, remain unchanged.

State Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 3-19.e
Witness: Donald A. Murry

Data Request:

3-19.e. If Western's WNA is approved as proposed, would Western be assessed by investors as having closer to the same level of risk as the other two groups depicted in Schedule DAM-18? Explain the answer in detail.

Response:

e. Yes. A WNA reduces the risk associated with the variability in earnings in a given year because of weather. However, the approval of the WNA will remove only a portion of the variability from Western Kentucky's revenue and common stock earnings. It will also not alter the other sources of business and financial risk.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 20
Witness: Betty L. Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 7 of 10 of the Application, Tab 4, exhibit FR 10(9)(o). The referenced "monthly budget variance reports provided in response to FR (9)(n)" do not satisfy the filing requirement. The reports supplied in FR (9)(n) have no further breakdown of expenses beyond operations and maintenance. Additionally, no narrative explanations were provided, as required by 807 KAR 5:001, Section 10(9)(o). Ms. Adams' testimony indicates Western's operating budget is prepared by cost center and individual functional expense. The response to the AG's August 19, 1999 Data Request, Item 175, Schedule A, Page 1 of 1, provides a comparison of budgeted operations and maintenance ("O&M") expenses (without employee benefits) by responsibility area for Western. The response to Item 176, in that same data request, states that "variance explanations are communicated verbally." However, Ms. Adams' testimony at page 6 states that Ms. Adams reviews variance reports for cost centers which "exceed the monthly budget by five percent (5%) or more," then "document[s] for future budgeting purposes, known changes in current operational spending from budget."

a. Explain whether the testimony is correct in stating certain variances of operational spending from budget are documented, or merely communicated verbally.
b. Western's response to the AG's August 19, 1999 Data Request, Item 175, states that the "threshold below which O&M budget variances are evaluated is 10 percent." Is 10 percent or the 5 percent referenced in Ms. Adams' testimony the threshold for evaluation of variances? Explain the response.

Response:

a. Documentation includes verification of the reasons for variance, often communicated verbally, and retention of variance reports for future reference. Separate documentation is also made in the format as shown in our response to AG 175, Schedule A, which is an in-house analysis of the comparison of actual versus budget. Upon the monthly review by WKG's staff, detail of the variances greater than 5% are given verbally by the functional VP.
b. AG's August 19, 1999 Data Request, Item 174, asks if there is a threshold similar to the 5% in instances where actual costs are below budget. Our response was that the threshold was 10% for variances below budgeted amount.

Notes

21

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 21
Witness: Betty L. Adams

Data Request:

The response to the AG's August 19, 1999 Data Request, Item 175 (should be 176), Schedule A, Pages 1, 8, 13, 18, 22, 26, 3 0, and 33 provides monthly O&M budget to actual variances for October 1998 through May 1999.

a. Provide narrative explanations by cost center and functional expense of variances in these reports as required by 807 KAR 5:001, Section 10(9)(o). A narrative explanation for employee benefit variances may be provided on a monthly basis for Western in total. Use 10 percent as the minimum threshold to determine the variances requiring explanation. Additionally, provide these variance analyses and narrative explanations of variances greater than 10 percent for the months of June 1999 through September 1999 by November 15, 1999.
b. Provide the variance analyses with narrative explanations for variances greater than 10 percent, as referenced in (a) above for the 12 months immediately prior to the base period, as required in 807 KAR 5:001, Section 10(9)(o).

Response:

Western is providing in separate binders, the detail reports by cost center and functional expense for October 1998 through August 1999 of the base period and the 12 months immediately prior to the base period. The detail reports are too voluminous to reproduce multiple copies; therefore we are providing two copies for the Commission and one for each intervenor. If the Commission requires additional copies, please advise.

As can be seen, narrative explanations are not generated by the system. Western has 29 cost centers in the base period of which we track 10 primary cost elements. To create narrative information would require evaluation of 3,480 group cost accounts.

For the 12 months immediately prior to the base year, there were 44 cost centers. To create narrative information would require evaluation of 5,280 group cost accounts.

Please reference our response to KSPC 3-38 for additional narrative.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 22a
Witness: Betty L. Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922ministrative Expenses Transferred – Credit" is not in accordance with the FERC USoA.

a. Explain how the use of Account 922 for Shared Services costs allocated to Western compiles with the FERC definition that Account 922 is for "administrative expenses…(from) Accounts 920 and 921 which are transferred to construction costs or non-utility accounts."

Response:

a. The Company uses the 922 FERC account for transfers of costs both to and from the Administrative and General Salaries account and the Office Supplies and Expenses account since there is no other FERC account defined for costs to be allocated to Western. This allows the utility to have direct charges in the 920 and 921 accounts as well as the 930.2 Miscellaneous General Expenses account recorded separately from the allocated charges. The types of expenses listed are consistent between periods as is the account 922 which is where $6,859,312 in charges resided in FY 1994 the test period used in our last rate case.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 22b
Witness: Betty Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the Application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922 "Administrative Expenses Transferred - Credit" is not in accordance with the FERC UsoA.

b. The schedule of Shared Services "Combined Direct & Billed" total monthly expenses as allocated by division on the exhibit in response to DR Item 83a, "April's Financial Statements," bottom of the page marked "(33),(34) and (35)" appears to represent a detailed statement of operating expenses. Prepare this detailed statement of operating expenses showing the total six months actual activity and the projected six months total in the base period. Additionally, prepare a similar detailed statement of operating expenses showing total balances for the forecasted test year. Be sure that the amounts are reconciled to the amounts included on the FR 10(9)(h)1 and FR 10(10)(i)1 as described in (c) below.

Response:

Shared Services Combined Direct & Billed Expense - Western Portion (000's) - Base Period

Financial Item	Oct 98	Nov 98	Dec 98	Jan 99	Feb 99	Mar 99	Apr 99	May 99	Jun 99	Jul 99	Aug 99	Sep 99	Base Pd
SSU O&M	739	736	756	418	951	419	703	670	674	697	682	687	8,132
Depreciation	153	153	389	159	159	164	80	80	80	80	80	81	1,658
Taxes Other Than Income	11	15	11	15	8	74	13	13	13	13	13	13	212
Total SS Charges	904	904	1,156	592	1,118	657	796	763	767	790	775	781	10,002

Shared Services Combined Direct & Billed Expense - Western Portion (000's) - Forecast Period

Financial Item	Jan 00	Feb 00	Mar 00	Apr 00	May 00	Jun 00	Jul 00	Aug 00	Sep 00	Oct 00	Nov 00	Dec 00	Fcst Pd
SSU O&M	703	687	680	716	683	687	709	695	699	752	707	709	8,427
Depreciation	118	118	118	118	118	118	118	118	118	137	137	138	1,474
Taxes Other Than Income	13	13	12	13	13	12	13	13	12	13	13	12	152
Total SS Charges	834	818	810	847	814	817	840	826	829	902	857	859	10,053

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 22c
Witness: Betty L. Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922ministrative Expenses Transferred – Credit" is not in accordance with the FERC USoA.

c. The answer to the commission's August 19, 1999 Order, Item 57, is non-responsive. A reconciliation should consist of detailed items comprising the approximate $953,000 difference for "Shared Services Billing" on DR 67(f) of $10,003,000 and Administrative Services Transferred on DR 67(g), Schedule C-2.1, Sheet 4 of 10, account 922, in the amount of $9,050,095. Provide a list of the items posted to different accounts that make up this difference.

Response:

c. See attached schedule.

Western Kentucky Gas Company
Case #99-070
SSU Billing Direct & Allocated
For the Test Period ended 12/31/00 & the Base Period ended 9/30/99

Account	Test Period SSU Billing	Base Period SSU Billing
	$	$
7420 Mfg Gas Prod-Mt-Maint Of	0	0
7500 Ng Prod-Op-Op Suprvsn & Engineering	0	0
7560 Ng Prod-Op-Fld Meas&Regst	0	0
7580 Ng Prod-Op-Gas Well Royal	0	0
7660 Ng Prod-Mt-Maint Fld Meas	0	0
7980 Expl&Dev-Op-Other Explora	0	0
8030 Prod Exp-Ng Trsm Line Pur	0	0
8040 Prod Exp-Ng City Gate Pur	0	0
8070 Prod Exp-Purchases Gas Ex	0	0
8080 Prod Exp-Gas W/D From Str	0	0
8090 Prod Exp-Gas Delvd To Str	0	0
8120 Prod Exp-Gas Used Oth Uti	0	0
8140 Ng Stg Exp-Op Suprvsn & E	0	0
8160 Ng Stg Exp-Op-Wells Expen	0	0
8170 Ng Stg Exp-Op-Lines Expen	0	0
8180 Ng Stg Exp-Op-Comp Statio	0	0
8190 Ng Stg Exp-Op-Comp Sta Fu	0	0
8200 Ng Stg Exp-Op-Meas&Reg St	0	0
8210 Ng Stg Exp-Op-Purificatio	0	0
8240 Ng Stg Exp-Op-Other Expen	0	0
8250 Ng Stg Exp-Op-U/G Op Roya	0	0
8310 Ng Stg Exp-Mt-Maint Struc	0	0
8320 Ng Stg Exp-Mt-Maint Reser	0	0
8330 Ng Stg Exp-Mt-Maintenance	0	0
8340 Ng Stg Exp-Mt-Maint Comp	0	0
8350 Ng Stg Exp-Mt-Maint Meas/	0	0
8360 Ng Stg Exp-Mt-Maint Purif	0	0
8410 Other Storage Exp	0	0
8470 Other Storage Exp	0	0
8500 Trsm-Op Opr Suprvsn/Eng	0	0
8560 Trsm-Op Mains Expenses	0	0
8570 Trsm-Op Meas&Reg Sta Exp	0	0
8590 Trsm-Op Other Expenses	0	0
8620 Trsm-Maint Struct & Impro	0	0
8630 Trsm-Maint Of Mains	0	0
8640 Trsm-Maint Comp St Equip	0	0
8650 Trsm-Maint Meas&Reg Stat	0	0
8670 Trsm-Maint Oth Equipment	0	0
8700 Distr-Op Oper Supervsn&En	0	186,036
8710 Distr-Op Distr Load Disp	0	0
8720 Distr-Op Distr Comp Sta F	0	0
8740 Distr-Op Mains & Serv Exp	0	(44,374)
8750 Distr-Op Meas&Reg Sta-Gen	0	0
8760 Distr-Op Meas&Reg Sta-Ind	0	0
8770 Distr-Op Meas&Reg Sta-Cty	0	0
8780 Distr-Op Mtr & Hous Reg E	0	2,493
8790 Distr-Op Cust Install Exp	0	1,425
8800 Distr-Op Other Expenses	0	0

Western Kentucky Gas Company
Case #99-070
SSU Billing Direct & Allocated
For the Test Period ended 12/31/00 & the Base Period ended 9/30/99

Account	Test Period SSU Billing	Base Period SSU Billing
8810 Distr-Op Rents	0	0
8850 Distr-Maint Suprvsn & Eng	0	32,226
8860 Distr-Maint Struct & Impr	0	0
8870 Distr-Maint Of Mains	0	(31,514)
8890 Distr-Maint Meas&Reg Sta-Gen	0	0
8900 Distr-Maint Meas&Reg Sta-Ind	0	0
8910 Distr-Maint Meas&Reg Sta-City	0	0
8920 Distr-Maint Of Service	0	0
8930 Distr-Maint Mtrs&Hous Reg	0	0
8940 Distr-Maint Other Equip	0	0
9010 Cust Accts-Op-Supervision	0	0
9020 Cust Accts-Op Meter Exp	0	(7)
9030 Cust Accts-Op Record&Coll	0	208,229
9040 Cust Accts-Op Uncol Accts	0	0
9050 Cust Accts-Op Misc Acct	0	0
9090 Cust Serv-Op Supervision	0	0
9100 Cust Serv-Op Assist Exp	0	1,188
9110 Cust Serv-Op Info Adv Exp	0	0
9150 Sales Promo-Op Supervsn	0	0
9160 Sales Promo-Demo&Sell Exp	0	350
9170 Sales Promo-Op Promo Adv	0	0
9180 Sales Promo-Op Misc Promo	0	0
9200 A&G-Op Admin & Gen Salari	0	0
9210 A&G-Op Office Sup & Exp	0	16,160
9220 A&G-Op Admin Exp Trsfd-Cr	10,052,965	9,050,095
9230 A&G-Op Outside Serv Empld	0	68,153
9240 A&G-Op Property Insurance	0	20,393
9250 A&G-Op Injuries & Damages	0	272,422
9260 A&G-Op Empl Pen Benefits	0	189,683
9270 A&G-Op Franchise Requrmnt	0	0
9280 A&G-Op Reg Comm Exp	0	6,828
9301 A&G-Op Inst/Goodwill Adv	0	0
9302 A&G-Op Misc General Exp	0	22,394
9320 A&G-Maint General Plant	0	0
Total SSU Billing	$10,052,965	$10,002,180

Notes: Debits are shown as positive, and credits as negatives.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 22d
Witness: Betty Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the Application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922 "Administrative Expenses Transferred - Credit" is not in accordance with the FERC UsoA.

d. Refer to the detailed statement of operating expenses in (b) above. Provide detailed descriptions of the types of expenditures and amounts for the base period and forecasted test year for items the lesser of $10,000 or 10 percent of the account total. For all lesser amounts, provide explanations of the various types of expenditures comprising the remainder.

Response:

Refer to the response to part e of DR Item 22. These amounts represent the NARUC accounts for the forecasted test year for Shared Services operating expenses. The same amounts and allocations will be used for the last six months of the base period. The major components of the elements are labor, benefits, contract labor, outside services, utilities, and technology and communications expenses. Services provided to Western are found in the Shared Services contracts as provided in the previous Data Request KPSC 1-83b. As for providing the details of the transactions that are the lesser of $10,000 or 10 percent of the account total, the Company feels that providing this would not provide a material benefit over what has previously been filed. The analysis would be extremely voluminous in that it would require the review of hundreds of thousands of transactions requiring hundreds of man-hours.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 22e
Witness: Betty Adams

Data Request:

Refer to the Direct Testimony of Betty L. Adams and the forecasted test period filing requirements at Volume 9 of 10 of the Application, Tab 2, Exhibits FR 9(u)1, and Schedules 1-3 and Exhibit A. The referenced Schedules 1-3 and Exhibit A do not satisfy the filing requirement of providing a detailed description of the amounts allocated. Furthermore, the answers to the Commission's July 16, 1999 Order, Items 34(a) and 83(a) were non-responsive. It appears, based on the information in the record at this point, that the recording of the $9,050,095 of Shared Services cost allocated to Western in Account 922 "Administrative Expenses Transferred - Credit" is not in accordance with the FERC UsoA.

e. Provide the Shared Services detailed statement of operating expenses cross-referenced to corresponding FERC account numbers.

Response:

This will tie to FR 10(9)(u) Schedule 2 - Sub Total line

Shared Services NARUC Account Detail of the Forecast Period (000's)

NARUC	Jan 00	Feb 00	Mar 00	Apr 00	May 00	Jun 00	Jul 00	Aug 00	Sep 00	Oct 00	Nov 00	Dec 00	Fcst Pd
8700	18	18	19	18	7	20	20	19	3	19	9	8	179
8710	7	8	0	0	0	0	0	0	0	2	2	2	21
8790	12	12	12	11	1	11	12	11	0	11	1	0	95
8810	6	6	6	8	8	10	8	8	2	6	6	6	80
9010	12	12	12	11	1	11	12	11	2	11	1	0	97
9030	54	35	40	50	116	30	44	44	38	33	81	41	607
9200	203	203	216	223	213	221	220	225	267	202	192	248	2,635
9210	100	136	116	113	78	132	109	117	119	145	113	127	1,404
9230	107	108	107	105	105	105	106	105	105	135	107	109	1,305
9240	0	0	0	0	0	1	0	0	0	1	1	0	3
9250	28	11	27	28	21	28	30	26	2	30	40	21	290
9260	178	162	166	173	183	174	169	167	180	177	184	167	2,081
9300	2	7	7	2	0	0	2	0	0	2	0	0	20
9302	42	34	16	33	18	37	44	27	22	19	25	36	354
9310	55	48	56	63	54	34	63	53	77	59	61	58	680
9320	15	21	15	14	14	8	6	16	18	28	13	14	182
Total	839	823	816	851	818	822	845	830	835	881	836	838	10,034

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 23
Witness: Betty L. Adams

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 1(c). The response states that no assets, liabilities, capital, or personnel of Western or Atmos Energy Corporation ("Atmos") were directly transferred to either WKG Storage, Inc. or WKG Energy Services, Inc. Were any of Western's assets, liabilities, capital, or personnel indirectly transferred to wither of these affiliates? If yes, explain the nature of the transfer.

Response:

None of Western's assets, liabilities, capital, or personnel were indirectly transferred to these affiliates.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item #24
Witness: Burman

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 2. Based on the definition of "affiliate" in 807 KAR 5:001, Section 10(1)(b)10 and (1)(b)11, the five unincorporated divisions of Atmos are considered to be affiliates. Based on this clarification, and excluding those shared services transactions already described in this record, provide the information originally sought by this request.

Response:

Western does not concur with the statement that pursuant to 807 KAR 5:001, Section 10(1)(b)10 and (1)(b)11, that Western or any other business unit is an affiliate of Atmos. As Western stated in Item 2 of its response to the Commission's August 19, 1999 Order, Western, along with the other four LDC business units of Atmos, are unincorporated divisions of Atmos. As such, Western is not a separate legal entity as that term is used in the regulations and thus it is not an affiliate of Atmos. Atmos is relevant the legal entity conducting business in Kentucky under the name Western Kentucky Gas Company pursuant to a certificate filed with the Kentucky Secretary of State. Consequently, it cannot legally enter into affiliate transactions with itself, i.e., Atmos or other Atmos business units.

With regard to the specific questions posed in KPSC #2 - DR Item 2, Western's responses remain the same, except as follows:

Revised Response to KPSC #2 –2.

a. See response to AG #2 – 2.

b. None. However, see response to KPSC #3 - 1.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 25
Witness: Donald P. Burman

Data Request:

25. Refer to the response to the Commission's August 19, 1999 Order, Item 3. Entry number 2 is shown as two debits, without a corresponding credit. Indicate whether the entry shown is correct or, if in error, provide the correct entry.

Response:

The correct Entry #2 is as follows:

040.0000.1070.01290.009xxx.0000		
Construction Work in Process – Benefit Load	XXX	
040.000.1840.13803.009000.0000		
Clearing Account – Benefit Clearing		XXX

To record capitalized benefits offset from the Projects Accounting System

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 26
Witness: Donald P. Burman

Data Request:

26. Refer to the response to the Commission's August 19, 1999 Order Item 4(c). Explain in detail why information on Western's post-retirement employee benefits is not available for years prior to the fiscal year ending September 30, 1996.

Response:

The requested information was located off-site, but has been retrieved and is shown below.

a. Expected retiree claims and administration costs, less retiree contributions:

(1)Forecasted and base periods:	$827,500;
(2)Fiscal year ending 09/30/98:	$615,400;
(3)Fiscal year ending 09/30/97:	$558,600;
(4)Fiscal year ending 09/30/96:	$533,600;
(5)Fiscal year ending 09/30/95:	$655,044;
(6)Fiscal year ending 09/30/94:	$507,550.

b. Actuarially determined annual OPEB cost:

(1)Forecasted and base periods:	$1,583,200;
(2)Fiscal year ending 09/30/98:	$1,430,400;
(3)Fiscal year ending 09/30/97	$1,478,000;
(4)Fiscal year ending 09/30/96:	$1,395,500;
(5)Fiscal year ending 09/30/95:	$1,456,900;
(6)Fiscal year ending 09/30/94:	$1,535,800.

c. Actuarially determined OPEB liability recorded as of:

(1)09/30/98,most recent actuarial study	$5,891,300;
(2)09/30/97	$3,911,500;
(3)09/30/96	$2,360,000;
(4)09/30/95	$1,830,100;
(5)09/30/94	$1,028,300.

The information for fiscal years 1998, 1997 and 1996 was obtained from the annual "Analysis of Postretirement Benefits" prepared by Ernst & Young LLP. The cost information for 1995 and 1994 was obtained from annual report workpapers for fiscal 1994 and 1995. The most recent actuarial report available is for the year ended 9/30/98. Base period and forecast period costs are estimated to approximate the expected fiscal 1999 costs provided in the 1998 report.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 27
Witness: Gary Smith

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 6. The second paragraph of this response makes reference to an adjustment to the "test year" in this case. Clarify whether this reference is to the base period or the forecasted period.

Response:

This reference is to Western's determination of the forecasted period. The second paragraph of the response the Commission's August 19, 1999 Order, Item 6, describes the revenue budgeting process utilized in the Company's determination of the forecasted period of January 1, 2000 to December 31, 2000.

Notes

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 28
Witness: Gary Smith

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 6. In this response, Western has filed an update to its original weather adjustment schedules Exhibit GLS-4, using billing information through May 1999. KRS 278.192(2)(b) states that the actual results for the estimated months of the base period shall be filed no later that 45 days after the last day of the base period. 807 KAR 5:001, Section 10(8)(d) states that after an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless such revisions reflect statutory or regulatory enactments that could not have been included in the forecast on the date it was filed.

a. If the update to Exhibit GLS-4 is related to the base period, explain why this information was filed covering a period other than the end of the base period.

b. If the update to Exhibit GLS-4 is related to the forecast period, explain in detail why Western is not in violation of 807 KAR 5:001, Section 10(8)(d).

Response:

a. The information submitted in the Company's response to the Commission's August 19, 1999 Order, Item 6 was not an intended as a revision or replacement for Exhibit GLS-4 (Mr. Smiths testimony at Volume 2 of 10, Tab 11 of the Company's Application). Exhibit GLS-4 is a weather-normalization adjustment to fiscal year 1998 volumes. The information provided by Western in KPSC DR 2 - Item 6 is a weather-normalization adjustment to a twelve-month period ending May 1999.

Exhibit GLS-4 was provided, along with Exhibits GLS-3 through GLS-6, to document the Company's development of the revenue budget for the forecasted test year of January 1, 2000 to December 31, 2000. Mr. Smiths testimony at page 9, line 28 through page 11, line 17, explains the purpose of the weather adjustment represented by Exhibit GLS-4.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 28
Witness: Gary Smith

Exhibit GLS- 5, as stated in Mr. Smiths testimony at page 12, line 28 through page 13, line 16, projects the continued effects of declining residential/commercial usage. Information submitted by the Company in response to the Commission's August 19, 1999 Order, Item 6 provides data not available at the time of the Company's filing of the Application, revealing a continued decline in weather-normalized residential consumption since the end of fiscal year 1998.

This information does provide data utilized in the Company's base period (fiscal year 1999), some of which was estimated at the time of the filing of the Application in this Case.

Western will file the actual results for all of the estimated months of the base period no later that 45 days after the last day of the base period.

b. Western proposed no adjustment to the forecast period in its submittal of this information in the Company's response to the Commission's August 19, 1999 Order, Item 6. This newly available data merely supports and confirms the continued decline in residential usage, which was projected by the Company in its forecasts for the future test year. Please refer to testimony at Volume 2 of 10, Tab 11, Page 12, line 28 through Page 13, line 16, and the Company's responses to KPSC DR 1 - Item 59(b), KPSC DR 2 - Items 49 and 50, and AG DR 1 - Items 137, 151 and 152.

29

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 29
Witness: David H. Doggette

Data Request:

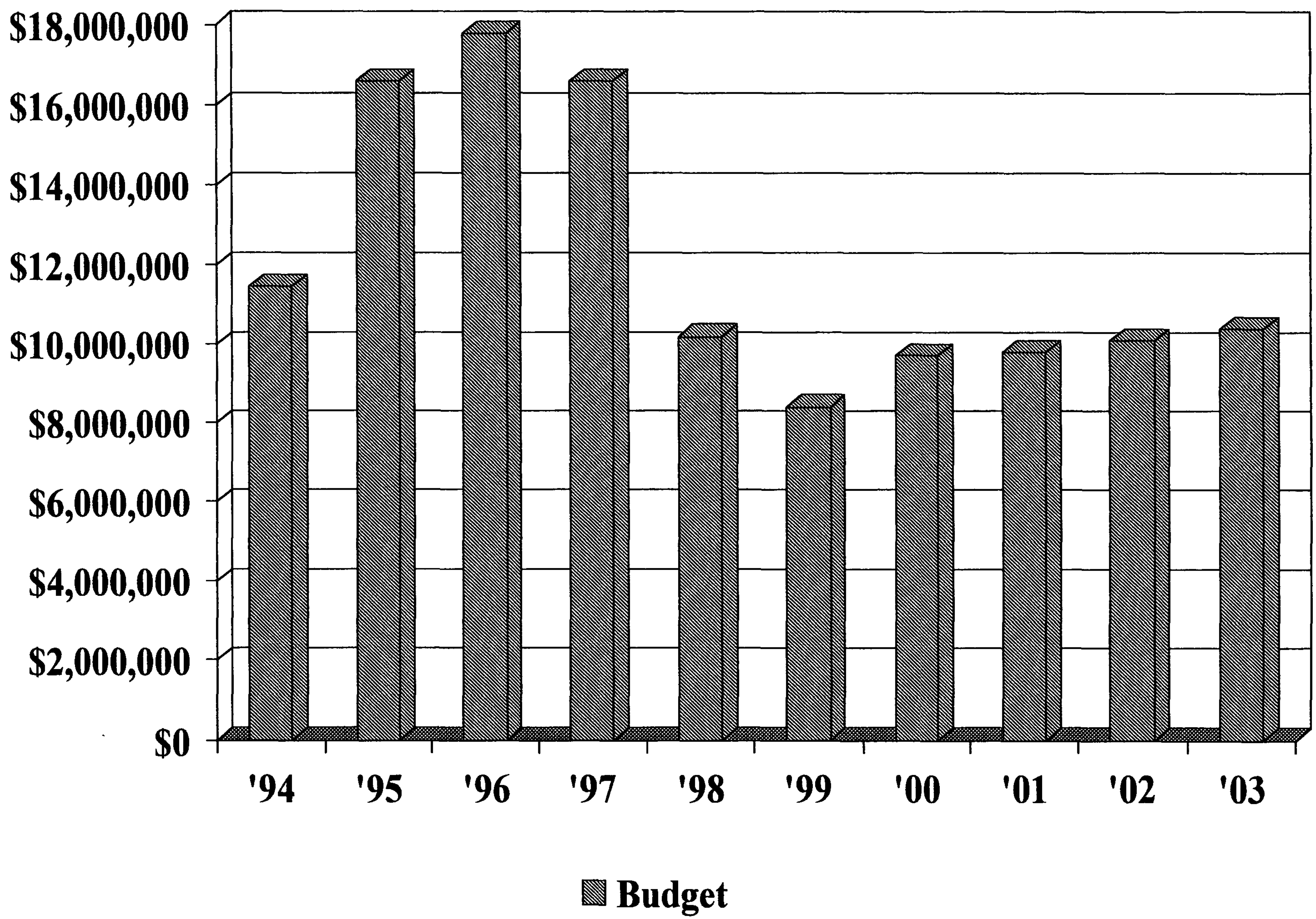
29. Refer to the response to the Commission's August 19, 1999 Order, Item 7. Indicate where in this record Western has provided an analysis showing that the results of the "baseline" forecasting of the capital budget correlates with prior years budgeted and actual amounts. If such an analysis has not been submitted, provide such an analysis.

Response:

Our "Beliefs and Behaviors" (see Mr. Gruber's testimony, Exhibit CEG-1) encourage us to set stretch goals for the enterprise. The forecasted Test Year Capital Budget of $9.7 million is a stretch goal. Western believes that not only is this goal attainable but it can be achieved while maintaining the safety and reliability of our system. We also believe that we can utilize new business processes and technology to further improve customer service and satisfaction. The capital budgets for Fiscal Years 1994 through 1998 range from approximately $10.2 million to approximately $17.7 million, please see Schedule 1. The actual expenditures for that five-year period vary from approximately $10.9 million to approximately $15.5 million, please see Schedule 2.

Simply by comparing these amounts to the forecasted capital budgets (shown in Volume 2 of 10, Tab 5, Exhibit DHD-1) for Fiscal Years 2000 through 2003, ranging from approximately $9.7 million to approximately $10.4 million, it is evident that the forecasted capital budgets are well within reason. In fact, mathematical or statistical projections based on the historical budget and actual expenditures would have resulted in higher average projected budgets for the forecasted periods (Budget average - $14.5 million and Expenditure average - $13.4 million). Any economic trending for increasing costs or inflation applied to the historical data would have pushed the projections even higher. Please see Schedules 1& 2.

Schedule 1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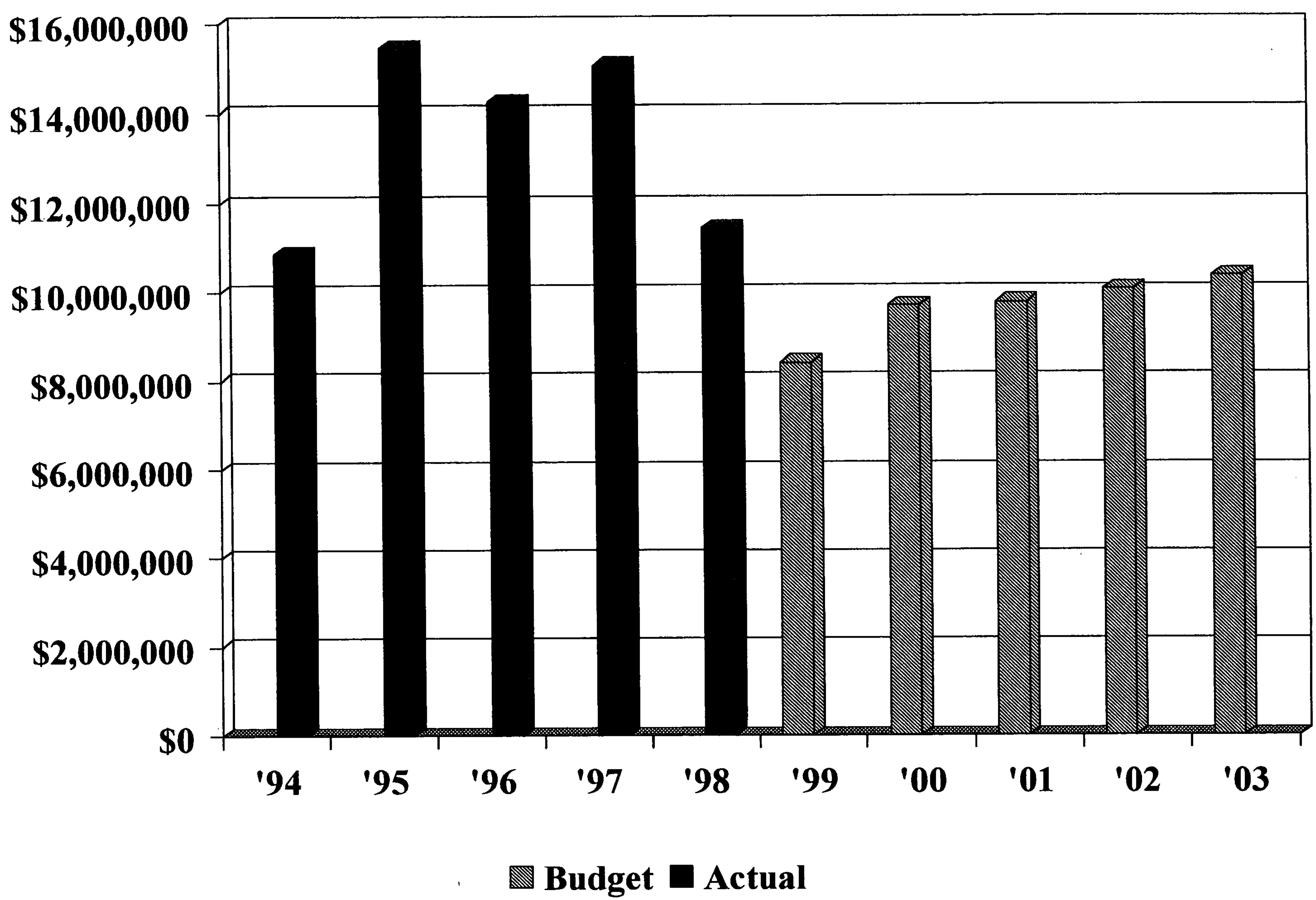
Schedule 2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Budget
Actual

30

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 30
Witness: David H. Doggette

Data Request:

30. Refer to the response to the Commission's August 19, 1999 Order, Item 9 and the supplemental response to the Commission's July 16, 1999 Order, Item 10, filed on August 18, 1999. Western was requested to provide the workpapers and assumptions used to determine that the projected increase in maintenance and improvements should be 36.25 percent for the FY 2000 capital budget. Western has not provided the requested workpapers nor adequately explained the assumptions used to make the 36.25 percent determination. Provide the originally requested information; this is the third request for this information.

Response:

Please see the response provided to the Attorney General's Supplemental Data Request, Item 5.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 31
Witness: David H. Doggette

Data Request:

31. Refer to the response to the Commission's August 19, 1999 Order, Item 9(b).

a. Provide the supporting workpapers for the $2,048,660 in maintenance and improvements for 1993.

b. Explain the reason(s) for the increases and decreases experienced by Western for maintenance and improvements for 1996, 1997, and 1998.

Response:

a. The response for this item 9(b) in the Commission's August 19, 1999 Order, "Maintenance and Improvements-FY 1993" was inadvertently omitted due to a printing error. The original intended response is attached as KPSC DR3-31, Schedule 1.

b. FY 1996 expenditures were lower than FY 1995 by approximately $734,000 because the transmission lines in Bowling Green and Shelbyville had been completed, and reduced highway relocations in 1996.

FY 1997 expenditures increased by approximately $2,152,000 over FY 1996 due to need for pressure improvements and highway relocations in Owensboro, greater number of service replacements for leakage in Bowling Green and the inclusion of WKG overheads in reporting actual expenditures.

FY 1998 expenditures were lower than FY 1997 by $1,305,650 due to reduced system reinforcement and highway relocations in Owensboro, reduced well workovers in Storage, and lower leak repairs in Paducah and Bowling Green.

WKG CAPITAL BUDGET PROJECTS FY 1993

Maintenance And Improvements

Budget No.	Description Operating Area	Budget Amount	Expenditure Amount
	Owensboro Operations		
36740	Mains Cathodic Protection	$ 2,000	$ -
37620	Blanket Mains Public Improvements	$ 142,511	$ 112,317
37630	Blanket Mains Leakage	$ 38,700	$ 26,324
37640	Mains Cathodic Protection	$ 20,000	$ 3,031
37820	Gen M&R Sta Equip-Public Imp	$ 15,509	$ -
37910	City Gate M&R Sta Eq-Sys Imp	$ 3,123	$ 2,040
38030	Services Leakage	$ 110,000	$ 108,202
	Total	$ 331,843	$ 251,913

Budget No.	Description Operating Area		Budget Amount		Expenditure Amount
	Owensboro Storage & Transmission				
33400	Field Meas & Reg Station	$	8,266	$	4,232
35100	Structures & Improvements	$	14,750	$	10,934
35200	Well Workovers	$	159,240	$	22,467
35400	Compressor Station Equip	$	93,950	$	55,894
36720	Mains Public Improvement	$	160,694	$	-
36730	Mains Leakage	$	31,968	$	19,319
	Total Resp Ctr	$	468,868	$	112,846
	WKG Measurement Center				
36910	M&R Sta System Impr	$	15,875	$	15,627
37810	Gen M&R Sta Equip Sys Impr	$	10,000	$	-
37820	Gen M&R Sta Equip Public Impr	$	20,369	$	4,886
	Total	$	46,244	$	20,512
	WKG Technical Services				
35500	Measuring & RegulatingStation	$	40,897	$	21,285
36910	M & R Sta-Sys Imp	$	71,426	$	64,564
	Total	$	112,323	$	85,849

	Madisonville Operations		
36710	Mains-Sys Imp	$ 312,457	$ 285,878
36720	Mains-Public Imp	$ -	$ 58,886
36740	Mains-Cath Pro	$ 4,000	$ -
36910	M&R Sta-Sys Imp	$ 2,000	$ 1,800
37620	Mains- Public (Hwy) Relocations	$ 14,556	$ 38,028
37630	Mains- Leakage	$ 45,291	$ 123,499
37640	Mains- Cathodic Protection	$ 38,800	$ 25,660
37810	M&R Sta Equipment-Sys Imp	$ 1,790	$ 1,662
37820	M&R Sta Equip-Public Impr	$ -	$ 18,876
37910	City Gate M&R Sta Eq Pub Imp	$ 12,289	$ 8,633
38030	Services- Leakage	$ 110,000	$ 109,095
38510	Ind M&R Equip-Sys Imp	$ -	$ 11,055
	Total	$ 541,183	$ 683,073
	Paducah Operations		
36740	Mains Cathodic Protection	$ 2,000	$ -
37620	Mains- Public Improve	$ 531,839	$ 123,140
37630	Mains- Leakage	$ 70,428	$ 63,861
37640	Mains- Cathodic Protection	$ 10,000	$ 27,411
37910	City Gate M&R Sta Eq-Sys Imp	$ 2,594	$ 6,139
38030	Services- Leakage	$ 146,900	$ 44,190
	Total	$ 763,761	$ 264,741
	Bowling Green Operations		
36740	Transm Mains- Cathodic Protection	$ 2,000	$ -
36910	M&R Sta Sys Improv	$ 7,220	$ 3,676
36920	M&R Sta Public Improv	$ 19,663	$ 42,651
37620	Mains- Public Improv	$ 99,204	$ 111,435
37630	Mains- Leakage	$ 70,000	$ 102,290
37640	Mains- Cathodic Protection	$ 45,011	$ 30,771
37800	M&R Sta Sys Improv	$ -	$ 40,492
37910	City Gate M&R Sta Equip Sys Imp	$ -	$ 32,368
38020	Services- Public Improve	$ -	$ 5,514
38030	Services- Leakage	$ 174,000	$ 72,239
	Total	$ 417,098	$ 441,435
	Danville Operations		
36710	Mains-Sys Imp	$ 7,217	$ 7,346
36740	Trans Mains-Cathodic Protection	$ 14,000	$ 5,848
36910	M&R Sta- Sys Imp	$ 29,120	$ -
37620	Mains- Public (Hwy) Relocat	$ 173,613	$ 110,421
37630	Mains- Leakage	$ 88,040	$ 63,210
37640	Mains- Cathodic Protection	$ 30,000	$ 19,259
37810	M&R Sta Equip Sys Improv	$ -	$ 3,298
37910	City Gate M&R Sta Eq-Sys Imp	$ 64,151	$ 66,930
38030	Services- Leakage	$ 48,750	$ 54,766
38510	Ind M&R Equip Sys Imp	$ 18,012	$ 8,987
	Total	$ 472,903	$ 340,066
	WKG Overheads	$ -	$ (65,926)
	Grand Total	$ 3,041,900	$ 2,048,660

32

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 32
Witness: Buchanan & Gruber

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 12.

a. Explain why it is reasonable to assume that by the forecasted period, Western's number of employees will represent 20 percent of the number of employees for Atmos' total regulated operations.

b. The response indicates that historically, Western's percentage of the total number of employees has been slightly lower than its percentage of the total number of customers. Explain why Western expects this relationship to change in both the base period and the forecasted period.

c. Do the responses to parts (d), (g), and (h) for the forecasted period reflect the impact of the proposed revenue increase? Explain the response.

d. Explain in detail why Western's percentages of net operating income and net income are expected to decrease significantly in the base period and forecast period. Include a discussion as to how this can be expected to happen, given the corresponding percentages shown for parts (d), (e), and (f).

Response:

a. The number of Atmos' regulated operation employees represented by Western increases from 17% in fiscal 1998 to 20% in the forecasted period. This is reasonable given the reductions at United Cities Gas Co. (UCG) which reduced their employee count from 1,130 in 1997 to 540 employees by 2000, or 52%. WKG's employee count went down only 22% during this same period. This reduction in total regulated employees increases the percentage represented by Western. Since UCG is Atmos' largest business unit in terms of employees, its significant reduction in employee count substantially impacts the other units' relationship to the total.

b. Refer to the response in part a - since UCG is the highest growth company in terms of customers added, coupled with its reduction in employees without reducing customers, this shift is reasonable.

c. The revenue, net operating income, and net income percentages do not reflect the impact of the proposed revenue increase. Leaving this impact out further points to the need for the proposed rate relief.

d. Western's total sales margins are declining as shown in (d) as explained in Mr. Smith's testimony beginning on page 14 and the schedule attached to response AG #1 – DR 37. In spite of Western's plans to hold O&M costs flat, declining revenues and gross margins, even a small decrease, will result in substantially decreased operating income and net income. Even though Western has out performed its peers in O&M cost per customer and total cost paid by residential customer (see response to KPSC #3 - DR38), this performance has not been able to offset the decline in margin. This is our central plight, that despite our outstanding performance, margin loss has outpaced the efficiency and productivity improvements that we have made (see Supplemental Response to KPSC #1 – DR 6).

33

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 33
Witness: John P. Reddy

Data Request:

33. Refer to the response to the Commission's August 19, 1999 Order, Item 13(g). Western stated that the reasonableness of the assumptions used in the five-year plan is evaluated against historical occurrences and anticipated future operating conditions. Provide a further explanation of how Western performs this type of evaluation and indicate whether the evaluation is presented in writing or orally.

Response:

Guidelines and general assumptions are communicated at the beginning of each year's planning cycle. General assumptions are provided in writing (see attached document - Atmos 2000 Plan) by the corporate planning department to the business units and shared services departments and include the expected inflation rate, wage increase percentages, fringe benefits costs, short- and long-term interest rates, income tax rates, capital structure, dividend yield, expected share price, equity issuances, maintenance capital expenditures and similar assumptions. Generally, these assumptions reflect historical experience (i.e., what was last year's inflation rate) and anticipated changes (i.e., is the Federal Reserve expected to raise interest rates). Or, capital spending budgets may be adjusted for planned programs like specific customer service or technology initiatives. The utility business units like Western then develop their specific plans, taking into consideration factors that are unique to that business unit such as customer growth rates, staffing levels, training, and so forth. Once the individual business unit and shared service department plans are received, a consolidated financial plan is "rolled-up" for the Company.

Face to face Quarterly Performance Reviews (QPRs) with the Business Units typically involve presentations, so oral communications are supplemented with written material. See the responses to AG #1 – 176 & 192 for examples of presentation material. However, since the management of each Business Unit is held accountable for their own performance, the extent of written explanations for year-to-date performance rests largely with the Business Unit's need to explain under-performance. In the case of Western, it has performed very well in FY 1999 under the circumstances. It just needs higher rates. The detailed numbers are there if we need to look at them; we just place a greater value on planning and accountability than drafting written reports.

Atmos 2000 Plan

Atmos Energy Corporation
Five Year Business Plan
Business Unit Meeting
March 11-12, 1999

2000 Plan Kickoff:

I. Atmos Vision/Strategy Focus, Ownership

II. Corporate Financial Performance Goals & Challenges

III. Planning Calendar

IV. Financial Planning Assumptions/Approach

V. Templates

VI. Strategic Issues

VII. Other Issues

Atmos 2000 Strategic Plan

Planning & Budgeting Calendar

Event	Responsible	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Deliverables
New Planning Models to BU Controllers	P&B			6								*Upgraded 5-Year Financial Model (Excel)*
BU Planning Kick-Off Meeting	P&B BU Controllers			11-12								*Planning Guidelines (Benefits, Tax, & Interest Rates Capital Assumptions, Budget Responsibility, etc.)* *Template: Reconciliation of changes between '99 and '98 O&M & Capital Budgets* *Template: Reconciliation of changes between '00 - Last Year and '00 - Current (Income Stmt.)*
Planning Packet to Shared Services Units (SSU)	P&B			19								*Planning Guidelines (benefits rates, budget responsibility, Oracle considerations, Overheads, etc.)* *Template: SSU 5-Yr O&M & Capital Investment* *Template: SSU Monthly O&M & Capital ('99 & '00)* *Template: IT Strategy - Capital Investment and Depreciation for 5-Yrs and monthly '99, '00* *Template: Reconciliation of changes between '99 and '00 O&M Budgets*
First Draft of SSU Plans due to P&B	SSU's				8							*Completed Templates (see previous)*
SSU Information to BU Controllers	P&B				13							*All SSU Information (above)*
SSU Plan Review Meetings	P&B; Individual SSU's SSU Board Member(s)				14-16							*Discuss Issues / reconciliations / 'gap'*
1st Draft of BU Strategic Plans Due to P&B	BU Officers				20							*Completed Five-Year Strategic Plan* *Completed Five-Year Financial Model*
[Quarterly Performance Reviews]					*[27-28]*							
Individual BU Plan Review Mtgs-Confrnce Calls	P&B; Individual BU's Mgmt Comm											*Discuss 1st Drafts and Corporate Financial Plan (results of BU plan roll-up)*
- TransLa						10						
- Energas						11						
- Greeley						11						
- UCG						12						
- WKG						12						
- AESI						13						
- Propane						13						
SSU Final Plans Due to P&B	SSU's					20						*Updated templates (above)*
Communicate SSU Final Plans to BU's	P&B					28						*Updated templates (above)*

Atmos 2000 Strategic Plan

Planning & Budgeting Calendar

	Event	Responsible	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Deliverables
	2nd Draft of BU Financial Plan Due to P&B	BU Controllers						25					
Big Event	Present Corporate 5 year plan to Officers Group	P&B Atmos Officers							20				*Feedback from Officers; Management Understanding & Buy-In*
	[Quarterly Performance Reviews]								*[27-28]*				
Big Event	Preliminary Presentation of 2000 Plan & Budget to the Atmos Board of Directors	P&B; Larry Dagley								11			*Board Feedback / Direction for finalizing Plan*
Big Event	Presentation of Strategic Plans to Business Unit Management Groups (On site @ BU's)	BU Officers; P&B; Mgmt Committee								10-25			
	- AESI									10			*Travel to each BU*
	- Energas									11			
	- Greeley									12			
	- UCG									17			
	- Propane									18			
	- WKG									19			
	- TransLa									24			
	- SSU's									25			
	Final Feedback to BU's on 2000 Plans	P&B									3		
	Monthly 2000 Financials Due to P&B	BU Controllers									3		*Monthly Financial Statements from the Financial Model*
	Final Strategic Plans due to P&B	BU Controllers SSU's									10		
	Feedback to BU's on Monthly 2000 Financials	P&B									10		
	Final Monthly 2000 Financials Due to P&B	BU Controllers									17		*Monthly Financial Statements from the Financial Model*
Big Event	Presentation of Atmos 2000 Strategic Plan & 2000 Budget to the Board of Directors	P&B; Atmos BOD									23-24		*Approved Strategic Plan and 2000 Budget*
	SSU 2000 Contracts Signed	SSU's; SS Board; P&B									28		*Signed Contracts* *Reconciliation of Contract $'s to Budgets by BU*
	High Level Capital Budget Loaded into OFA (by Rate Division, by Category)	BU Controllers; P&B / SSU's									28		
	O&M Budgets Loaded into Oracle G/L System	BU Controllers; SSU's									29		
	High Level Capital Budget Loaded into Project Accounting	BU Controllers; P&B / SSU's									30		
	Review 2000 Planning & Budgeting Process	BU Controllers P&B										8	*Identify issues, solutions to improve the process for next year*

Introduction

In 1998, Atmos Energy Corporation embarked on a bold *new Vision to make the Company the largest provider of gas distribution services east of the Rocky Mountains with superior customer satisfaction ratings and the lowest O&M costs per customer of any peer group competitor*.

The fundamental strategy to achieve this vision is to build the Atmos team, run the utility operations exceptionally well, increase the size and market share of the non-utility operations, engage a partner to pursue "behind the meter" retail services, and grow through acquisitions.

The success of achieving the Vision and Strategy is very dependent upon being able to define a long-term plan that meets or exceeds analyst expectations for internal/earnings growth. Qualitative and financial plans must be developed at the business unit and shared service unit level that support the Vision and Strategy of the Company. Critical inputs to plan preparation include an understanding of Atmos' core competencies, linkages of competencies to opportunities, portfolio balance and overall strategic directions/issues (call center, rate strategy, new business ventures, core-related markets/businesses, pre-emptive strikes against threats to core businesses, etc.)

Intent

The purpose of this document is to provide business and shared service units with an understanding of the link between business plan preparation and achieving the Company's Vision and Strategy and to outline the guidelines for business plan preparation.

What will it take to achieve this vision?

- Maximizing profitable growth in utility BUs.
- Strong balance sheet.
- Financial "tool chest" to finance the growth of the business.
- Investing wisely, exercising financial discipline and living within our means.
- Successful merger / acquisition strategy.
- Run the utilities well – enhance the market position and profitability of each utility operation – Utility Profitability Strategy
  - Coordinate capital spending, cost increase, etc,. with rate cases to earn at least the authorized return in every jurisdiction, every year.
  - Increase earnings and cash flow annually through:
    - controlling costs and capital expenditures to amounts in rates; and
    - growing the number of customers served.
- Stay customer focused and deliver excellent, reliable service, at a low cost.
- Proactively work to achieve Gas Cost Incentive arrangements and Incentive Rates in every jurisdiction possible.
- Identify new revenue sources.
- Shared Service model that is efficient and facilitates growth.

What is this plan all about?

- Not just numbers.
- Roadmap for growing the business and value creation.

Reasons for a Five Year Plan

- Aligns business direction and initiatives with the Vision and Strategy.
- Sets stretch goals consistent with our Beliefs and Behaviors.
- Focuses plans and initiatives on expected changes in the business and regulatory environment.
- Forces discussion of important and sometimes difficult issues.
- Supports overall stock valuation.
- Measurement tool for future operating and financial results.
- Determines future financing needs/opportunities.
- Acts as "shark repellant"/value enhancement in takeover.
- Facilitates acquisition strategy.
- Develops enterprise thinking.
- Breaks the one-year budget cycle mentality.
- Without a roadmap, we cannot find the way to our destination and may not know when we get there.

The Five Year Plan also gives us a framework to:

- Maximize earnings and cash flow.
- Deliver consistent earnings and cash flow growth.
- Pursue only those projects that earn ROR in excess of their cost of capital.
- Analyze alternative strategies to determine which strategy generates the most shareholder value.
- Focus on risks and opportunities and their overall sensitivity to value creation.
- Determine what operations the Company may have, if any, that have limited value creation potential and should be considered for divestiture.

IT Strategy

The company IT strategy for the next five years is an investment that is critical to supporting our continued growth. The strategy includes several initiatives, which are key building blocks for integrating our business units and realizing our overall vision. The impacts of the initiatives will be to:

- Provide access to our financial and operating information in a timely manner
- Improve our utility and non-utility operations through enhancing information flows
- Increase effective communications within our company through standard platforms
- Support our low cost service provider strategy and perhaps further reduce O&M costs
- Enhance the service we currently provide our customers

The IT strategy is clearly a key step towards ensuring we attain our vision of being the largest provider of gas distribution services east of the Rockies. The specific goals of our IT strategy projects vary from standardizing our hardware and software to enhancing customer service to improving day to day operations. IT initiatives that are underway currently or will begin soon include:

- Implementing Oracle financial and HR systems (ORBIT project)
- Standardizing on failproof, Y2K compliant SCADA systems
- Implementing a new e-mail system (Outlook) and developing a corporate Intranet site (Inner Atmosphere) for improved internal communications
- Capturing engineering and field knowledge (maps) on CD-ROMs
- Further developing our Internet homepage to include web billing to customers

Long term, the IT Strategy will include projects to enhance work force management and gas management.

Achieving Best Practices in Shared Services

The implementation of Best Practices for all Shared Service units over the next five years is critical for the company to achieve the lowest O&M costs and to successfully compete in the marketplace. The overall objectives are:

- Ensure that every Shared Service produces a competitive quality product at an agreed level of service at a competitive market price (or is on the path to do so)
- Position the Shared Services organization for continuous improvement
- Achieve the above while maintaining a one team spirit

The goals identified to meet these objectives are:

- Streamline products/processes to increase level of service quality while reducing cost
- Identify products that the organization does not require
- Outsource products (process/system) where it makes sense
  - Strategically
  - Cost-based
  - Level of service
- Confirm/modify dedication of resource between shared services and business units
- Tighten the organization
  - Eliminate/reduce duplication of efforts
  - Realign spans of control

Contents of Five Year Business Plans – Business Units

OVERALL CONSIDERATION
- Mission Statement
- Key business initiatives / goals and specific course of action
- Market risks / threats, key trends, developments
- Impact of convergence
- Market characteristics
- Impact of unbundling
- Organizational structure
- Customer concentrations – by state, by class
- Competitors and their initiatives
- Map – geography of service territory
- Overall assessment of competitive position
- Market share / penetration – historical vs. projected
- Gas supply assessment – including map of suppliers
- Weather sensitivity – WNA (if applicable)
- Overall regulatory / rate strategy
- Profitability of growth
- Identify value added to organization
- Identify new or more efficient ways to add value
- Benchmark - determine your relative position among similar operations (stand alone operations as well as similar functions in other companies)
- Consider and understand how your vision affects key aspects of the organization, such as financial reporting, regulatory / pricing matters, technology, resources in other areas, etc.
- Consider long-term restructuring to increase value
- Overall Assumptions
  - General Inflation
  - Interest rates – short-term / long-term
  - Wage increases
  - Tax rates
  - Fringe Benefit costs
  - Billing to other Business Units
  - Cost of Shared Services

Income Statement and ROE
- Income statement
- Income statement statistics
  - Historical and projected customer growth (actual & percentage)
  - Historical and projected volumes by class
  - Historical and projected margin by class
  - Historical and projected rates by class
  - Historical and projected margin growth by class
  - Historical and projected rate cases
  - Historical and projected net income
  - Historical and projected O&M per customer
  - Historical and projected maintenance expense by customer class
  - Historical and projected employees per customer
  - Historical and projected payroll expense vs capitalized
  - Historical and projected actual ROE vs projected ROE

Income Statement and ROE continued

> Historical and projected ROE by regulatory jurisdiction
> Historical and projected marketing expenses per new customer / per margin added

- Income Statement Assumptions
  - Depreciation Rates
  - Bad debt expense / ratio
  - Property tax rates / costs
  - Training costs
  - Occupancy expenses
  - Disallowed operating expenses
  - Vehicle costs

Capital Expenditures

- Historical and projected capital expenditures by category
  - Vehicles
  - MIS
  - Equipment
  - Maintenance
  - Improvements
  - Growth

- Projected major capital expenditures
- Capital spending concentration (by state, location)
- Capital spending efficiency (growth expend. only)
  - Margin added
  - Return on growth expenditures
  - Cost per new customer
  - Cost per ft. main extension

- Historical and projected maintenance vs. depreciation
- Historical and projected analysis of capital budget
  - Direct labor & fringe benefits
  - Indirect labor & fringe benefits
  - Contractor utilization
  - Indirect OH
  - Corporate OH

- Historical and projected analysis of capital budget units
  - Feet and cost per foot of main extension
  - Feet and cost per foot of main replacement
  - Feet and cost per foot of relocations
  - Number of and cost per new service lines
  - Number of and cost per replaced service lines

Cash Flow & Balance Sheet

- Historical and projected cash flow
- Historical (to extent available) and projected balance sheet
- Historical and projected net cash flow
- Analysis of inventory / working capital levels

Assumptions for Five Year Plan

The following assumptions should be used as a guide in financial model preparation:

Description	Rate
General Expenditure Inflation	3%
General Wage Increase	_%
Fringe benefit load %	See Exhibit I
Short-term borrowing	6%
Federal/State Blended Income Tax Rate	38%
Dividend Policy	1999=$1.10; 4% annual increase
Capital Structure	50% - 50% target (incl ST Debt)

Schedule-Share Issue Price for Five Year Plan

	1999	2000	2001	2002	2003	2004
Share issue price	$ 30	$ 35	$ 37	$ 40	$ 44	$ 49
EPS [1]	$ 1.9~~6~~ 1	$ 2.04	$ 2.24	$ 2.47	$ 2.72	$ 2.99
18x PY EPS		$ 35.28	$ 36.72	$ 40.39	$ 44.43	$ 48.87

[1] 10%/year growth (after 2000)

Initial capitalization and shares outstanding will be established based on final FY 1998 balance sheet amounts. Each business unit will be responsible for meeting the stated dividend for their number of shares outstanding. Additional shares should be assigned to meet capital structure requirements.

Hurdle Rates for Capital Investments

For a publicly traded company like Atmos Energy Corporation, there are two primary ways to raise capital. Money can be borrowed from financial institutions like banks and pension funds or the company can raise equity capital through share issues to investors. In each case lenders and investors expect to get their investment back along with a return on that investment. Lenders receive interest on borrowed funds and shareholders receive dividends and, hopefully, a higher price for their stock when they sell it. Interest rates are negotiated and tend to move up or down with changes in the rates on risk-free government bonds. Returns required by equity investors also move with general economic conditions but expected returns vary with the relative riskiness of the company's activities compared to the stock market generally.

Required rates of return for investment purposes are often referred to as discount rates or "hurdle" rates, implying an obstacle that must be overcome. There are two aspects to this obstacle. First, a dollar received in the future isn't worth as much as a dollar today. Second, a risky dollar isn't as valuable as a certain dollar. The hurdle rate captures both of these effects. To compensate for the risk of a particular investment, stockholders expect to earn a return that exceeds the rate available on risk-free government securities like long-term Treasury bonds. Over the last sixty years, investors have expected to earn 4 to 5 percentage points above the return on Treasury bonds when investing in the stock of US corporations.

Economists have developed the concept of "Beta" to compare the riskiness of one investment to a broad basket of alternative investment opportunities. For example, if Company A's stock has a beta of 1, that means that its stock price moves up and down in lock step with the broader market for stocks. Similarly, a beta of 0.5 means that the company's stock price fluctuates only one-half of the market's movement on average. The concept of beta can be applied to individual projects as well as stock price movement.

In theory, each business unit within Atmos Energy Corporation has its own unique profile and optimal capital structure that minimizes its cost of capital. In the case of new products and services, the optimal capital structure and cost of capital will vary over time as a new product or service moves through its lifecycle. In the research, development and commercialization phase of a new product, the only feasible capital structure is that of 100% equity, since the new product has not generated earnings to support borrowing funds. However, if that product or service is successful and growth reaches a sustainable level, then a new business will add debt capacity to Atmos which will lower the weighted average cost of capital for that business. A standalone business unit with a diversified portfolio of new products and services would need to reach about $10 million in sales before it could support an industry average capital structure for competitive firms of 60% equity and 40% debt.

Economist use the concept of beta in a formula called the Capital Asset Pricing Model (CAPM) to estimate the cost of equity capital and, in turn, to develop hurdle rates. The CAPM states that:

> The cost of common equity = 10-year Treasury bond yield + beta (market equity risk premium) + an adjustment for project size or liquidity.

In practice, the CAPM yields a range of common equity rates for a typical investment or project. Beta's can vary depending on the degree of business risk and the amount of financial leverage. Equity risk premiums are not constant over time and must be updated periodically. Once the cost of equity capital has been estimated, it can be plugged into the formula for determining the firm's weighted average cost of capital.

The weighted average after-tax cost of capital (WACC) applied to a company as a whole and can be used as the hurdle rate for individual projects if they are carbon copies of the firm in terms of their business risks. The source of temporary financing (equity or short-term debt) does not affect the projects hurdle rate. What matters is the project's permanent capital structure or contribution to the firm's borrowing capacity. Capital structure is discussed in the next section. WACC is determined as follows:

WACC = [(cost of common equity%)*(% equity capitalization)]+[(1- marginal tax rate)* (% debt capitalization)*cost of debt %)]

Although utility capital structure has historically been recoverable through rates, utility business units need be attentive to the fact that capital expenditures do have a cost to the company and every dollar invested in plant or equipment should be scrutinized to ensure that a reasonable return will be realized. Likewise, non-utility units need evaluate and ensure capital investment enables the total corporation to meet its Vision & Strategy.

Capital Structure

For the foreseeable future, Atmos Energy Corporation is seeking to maintain its "A" credit rating on its debt securities. An "A" rating will preserve a financial cushion in the event of unanticipated increase in business risk. As the Company moves into an incentive ratemaking environment with performance based rates, regulatory restructuring and increased industry competitiveness may require a reduction in the utility debt ratio to maintain an "A" credit rating. This reduction would have a negative impact on the corporation's financial capacity to fund new growth opportunities if it causes Atmos to issue new equity or reduce the rate of future dividend increases.

The Company's policy is not to use any debt to finance dividends or to borrow funds on an annual basis in excess of the amount of equity retained in the company. In completing long-term plans business units should anticipate a strengthening of their capital structure to around 50% equity.

Capital Allocation Process

Capital is a resource like any other that needs to be carefully managed by the Company. The Company's current investment philosophy is to live within its means. That is, capital investment should not exceed cash generated from operations less dividends paid to shareholders. Stringent use of the Atmos Profitability Model will provide the Company with a better idea of profitable investment levels. As we follow this approach, earnings growth potential will be enhanced, and our capital structure target of 50% debt will be attained.

In preparing capital budgets several questions need to be asked concerning each request submitted for consideration.

For revenue enhancing or cost saving investments:

- Does the project being considered fit the overall strategy of the Company?
    - fit the Vision and strategy
    - help the BU to implement key strategies
    - pursue goals
    - address weaknesses
    - provide competitive advantages
- Can the request be deferred and still achieve the benefits. If so, what are the additional costs involved?

For non-revenue enhancing or non-cost saving investments:

- Does the investment being considered fit the Vision and Strategy?
- Are there other, less capital intensive, solutions?
- Can the project be deferred for a year or two? If so, what are the related cost/benefits?
- For safety driven investments;
    - What are the historical safety problems experienced?
    - Is the Company currently in compliance with federal/state regulations?
    - Are there alternative ways of minimizing risks without jeopardizing safety?

34

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 34
Witness: John P. Reddy

Data Request:

34. Refer to the response to the Commission's August 19, 1999 Order, Item 14. Western contends that it is reasonable to assume that the employee stock plans will continue to add roughly $20 million annually to Atmos's equity base.

a. Based on the information in this response, it would appear that Atmos and Western have based this assumption solely on the employee stock plan activity during FY 1999. Does Western agree with this conclusion? Explain the response.

b. The average dollar amount of the increase in Atmos's equity balance associated with the employee stock plans for the five previous fiscal years is approximately $10.5 million. Given this historic information, explain in detail why it is reasonable to assume that $20 million annually will be added to Atmos's equity base.

Response:

34. a. Atmos and Western have not based the assumption of annual stock issuances in the amount of $20 million "solely on the employee stock plan activity during FY 1999." The response to Item 14 of the Commission's August 19, 1999 order provides share issuance information for five fiscal years (1994 - 1998) plus the first nine months of FY 1999. As shown in that response, the most significant source of new equity issuance is the Company's Direct Stock Purchase Program ("DSPP"). Participants in the DSPP need not be employees of the Company. Participants in the DSPP may have all or a part of their dividends reinvested at a 3% discount from market prices. DSPP participants may purchase additional shares of Company common stock as often as weekly, up to a maximum of $100,000. Share issuances under the DSPP were 531,353 in FY1998 and 524,494 for the first nine months of FY 1999.

b. The DSPP was amended in December 1998 to make it even more attractive to investors by making it available to Roth IRA and Education IRA investors. Also, in December of 1997, the Company began issuing original shares for the DSPP rather than purchasing outstanding shares on the open market, thereby increasing the Company's equity base. Finally, since August 1997 when the United Cities Gas acquisition was completed, the Company has encouraged former UCG shareholders to participate in the Atmos DSPP program. In light of these changes, 1999 statistics for new stock issuance under the DSPP are more representative of investors' future appetite for participation in the Company's DSPP than prior years' figures.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 35. a.
Witness: Marks

Data Request:

35. Refer to the response to the Commission's August 19, 1999 Order, Item 15.

a. In the response to Item 15(d), Western states "it was our understanding that there were already guidelines in place based upon prior policy and regulatory rulings from the Kentucky Commission." Identify the guidelines, policies, and rulings this response is referencing.

Response:

The understanding came from information concerning programs that were already approved or had been filed for approval. Programs by LG&E, Kentucky Power Company and ULH&P were reviewed and discussed by the Collaborative to provide guidelines for the development of the WKG CARES DSM Program.

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

December 30, 1996

Mr. Jay F. Carnahan
Senior Vice President,
Technical Services
Western Kentucky Gas Company
P. O. Box 866
Owensboro, Kentucky 42302

Dear Jay:

Thank you for your letter and kind remarks about the Utility Conference in Lexington. We appreciate your attendance and your interest.

I have asked Ralph Dennis of our Gas Branch to contact you in setting up a meeting between you and the staff concerning the demand side management program. He should contact you soon with some dates.

Sincerely,

Don

Don Mills
Executive Director

DM:lb
cc: Ralph Dennis

Rec. 1-2-97.

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

January 3, 1997

Mr. Jay Carnahan
Senior Vice President,
Technical Services
Western Kentucky Gas Company
P. O. Box 866
Owensboro, Kentucky 42302

Dear Jay:

In your recent correspondence to Don Mills you requested a meeting to discuss Western's implementation of its demand side management program. After checking on your schedule, and that of appropriate Commission Staff, the meeting is scheduled for January 24, 1997 at 1:30 p.m. EST in Conference Room 1 of the Commission's offices.

We look forward to discussing Western's program with you. If any information is presently available for review prior to the meeting, please send me a copy and I will distribute it to Staff.

Please contact me if you have any questions.

Sincerely,

Ralph

Ralph E. Dennis
Manager, Gas Branch

c: Don Mills

Rec. 1-6-97.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 35. b.
Witness: Marks

Data Request:

35. Refer to the response to the Commission's August 19, 1999 Order, Item 15.

b. In the response to Item 15(d), Michael Marks makes reference to several representations that were relayed to him concerning the WKG CARES program. Keeping in mind that the Commission speaks only through its Orders, do either Mr. Marks or Western have in their possession any Commission Orders that approved the WKG CARES program? If yes, provide copies of those Orders.

Response:

There are no such Commission Orders. The meeting at which a member of the Collaborative briefed the Commission Staff is referenced in the attached letters.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 35. c.
Witness: Marks

Data Request:

35. Refer to the response to the Commission's August 19, 1999 Order, Item 15.

a. In the response to Item 15(k), it is stated that normal weather was based on actual weather for the 1980 – 1991 time frame as recommended in the Princeton Scorekeeping Methodology ("PRISM") software manual.

(1) Explain why the software manual recommended a 10-year period to use for the weather normalization.

(2) Explain why a 30-year period was not used for the weather normalization in the PRISM analysis, which is the time period normally used in weather normalization adjustments.

(3) Explain why Western believes the use of a 10-year period produces reasonable results for its PRISM analysis.

Response:

PRISM is considered, in the industry, to be the premier tool of its kind for the type of analysis which we conducted. The PRISM users manual recommends the use of the most recent 11 years of available weather data. When I provided this information in response to the prior question, I was citing the documentation provided by the authors of PRISM. I do not know why PRISM recommends the use of 11 years versus 30 years of weather data for normalization purposes. Attempts to contact the authors of PRISM, to date, have been unsuccessful.

36

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 36. a.
Witness: Smith and Marks

Data Request:

36. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145.

a. Who performed the analysis and developed the expense estimates shown on Exhibit MM-2 of the testimony of Michael Marks?

Response:

The expense estimates were developed under the direction of Mr. Gary Smith consistent with the mechanism set forth in Mr. Marks' testimony. These estimates were then reviewed by Mr. Marks and adopted into his testimony.

<u>Data Request:</u>

36. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145.

b. Explain why Western concluded that these estimated expenses did not need to be documented with supporting workpapers.

<u>Response:</u>

Exhibit MM-2 is itself the workpaper. MM-2 is supported by various source documents as follows: the attachment for the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145; the customer forecast filing requirement, FR 10(9)(h)14; and the Mcf sales forecasts filing requirement, FR 10(9)(h)15.

The estimates were projected from the historical data and the trends observed in the data as shown in the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145. These estimates are reflective of recently observed demand for this program and are consistent with the amount of weatherization work which the Community Action Agencies have demonstrated they are capable of performing for the WKG CARES Program.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 36. c.
Witness: Smith and Marks

Data Request:

36. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 2 of 3, Item 145.

c. The schedules of actual DSM program expenditures show that for the period from December 1996 through October 1998, Western expended $598,326. Using this historic information, explain in detail how Western and its DSM collaborative arrived at an estimated expense level of $268,000 for the period November 1998 through December 1999 and an estimated expense level of $200,000 per year for each of the following three calendar years.

Response:

The schedules of actual DSM program expenditures show that for the period from December 1996 through October 1998 Western expended $480,666.39 for weatherization expenses. The difference between this amount and the $598,326 is shown on the schedules as Collaborative expense which includes the cost of Program Design, Program Evaluation and consultant fees. There are no plans for further Program Design, Program Evaluation or consultant fees during the forecast 3 year period. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Item 231.a.

The $268,000 is an estimate for a 14 month period of which the 2 additional months are winter months which have been historically higher weatherization activity months. The $218,000 is an estimate from trends observed in the data from the schedules. The 2 additional months are estimated at a total of $50,000 bringing the total estimate for the 14 month period to $268,000.

The $200,000 is an estimate for each year of the forecast 3 year period. The estimate is from the trend of actual weatherization expenses and recently observed demand for this program and is consistent with the amount of weatherization work which the Community Action Agencies have demonstrated they are capable of performing for the WKG CARES Program. Additionally, the actual performance may vary from the estimate, but would be reconciled by a balancing adjustment described in my testimony on pages 20 and 21.

37

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 37. a. and b.
Witness: Marks and Smith

Data Request:

37. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Item 230.

a. During the planning stage of the WKG CARES program, did Western and its DSM collaborative consult with other utilities in Kentucky that had approved DSM cost recovery mechanisms, especially those approved under KRS 278.285?

b. If yes to part (a), explain how Western incorporated that information into WKG CARES. If no to part (a), explain why Western and its DSM collaborative did not undertake such a consultation.

Response:

a. Yes, prior to hiring AEG, there was contact with other utilities in Kentucky by Collaborative members.

b. The information obtained from filings and program design documents by LG&E, Kentucky Power Company and ULH&P was used as a guideline for WKG CARES Program design.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 37. c.
Witness: Adams

Data Request:

37. Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Item 230.

c. Explain how Western determined that the use of a deferred debit account was the most appropriate method to record WKG CARES program expenses.

Response:

Western recorded all WKG CARES program expenses in a specific deferred debit account so that the information could be easily retrieved/reviewed.

38

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 38
Witness: Gruber

Data Request:
Refer to the response to the AG's Data Request dated August 19, 1999, Volume 3 of 3, Items 176 and 192. Western has stated that for both its O&M budget variance analysis and the capital budget variance reports, variance explanations are communicated verbally during top management staff meetings and no written explanations are provided. Explain in detail why Western believes it is a sound and proper business practice not to document these budget variance explanations.

Response:
The type of documentation to which the question refers would only be a sound business practice if such documentation added value. Such documentation, in and of itself, is not a sound business practice unless it is essential to operating the business in an effective and efficient manner. Said another way, in the absence of such documentation, Western would be evidenced by ineffectiveness and inefficiency - which is simply not true. Our enterprise is among the lowest cost gas utilities. Those results speak for themselves. See attached Schedule A from FERC report data residing on the KPSC's website.

The emphasis at Western and Atmos has been to deliver results, not voluminous narratives on budget variances. Detailed budget variance reports are generated monthly, as provided in the response to KPSC 3-21. Atmos reviews overall utility performance measures each month and in Quarterly Performance Reviews (QPR's). Problem areas are usually reviewed and communicated in forums such as staff meetings, telephone calls, emails, QPR's, etc. The responsibility for detailed review of variances is at the Business Unit (BU) level. Each BU is trusted to use its own discretion to determine the most effective type of review. This latitude is consistent with the current organizational and management philosophy as emphasized in the Vision Statement attached as Exhibit CEG-1 to Mr. Gruber's testimony. Our Vision Statement emphasizes "Beliefs and Behaviors" which, at the top, encourages "leadership and accountability without micro-management." Another "Belief and Behavior" is "open and direct communication and feedback" which, as much as anything, is the key to our continuing success.

The organizational structure of Western and Atmos is lean and flat. This structure minimizes unnecessary effort and duplication of effort. Our structure encourages personal accountability and open communication, not memos and reports. Moreover, Atmos simply does not have the capacity to analyze, draft, and distribute narrative-based variance reports every month. The Shared Services Planning Department has averaged three full time employees for the past year. (One full-time person has also served on the Orbit conversion team.) To prepare these types of analyses at Western would require the addition of more financial analysts – a cost which is not currently reflected in the proposed test period cost of service.

1998 Comparative Financial Data
Kentucky LDCs

	Total Customers	Net Utility Plant	O & M Cost	Net Plant Per Cust.	O&M Cost Per Cust.	Residential Customers	Residential Revenue	Residential Rev. Per Cust.
Columbia Gas of Kentucky	137,306	$ 120,082,094	$ 27,458,234	$ 875	$ 200	123,156	$ 116,793,699	$ 948
Delta Natural Gas	37,074	$ 87,681,524	$ 6,516,721	$ 2,365	$ 176	32,111	$ 18,296,074	$ 570
Louisville Gas & Electric	286,762	$ 437,468,893	$ 39,763,125	$ 1,526	$ 139	264,570	$ 113,429,547	$ 429
Union Light, Heat & Power	78,952	$ 72,194,701	$ 15,353,188	$ 914	$ 194	72,176	$ 40,255,130	$ 558
Western Kentucky Gas	178,098	$ 108,110,426	$ 22,885,042	$ 607	$ 128	157,779	$ 52,026,313	$ 330
KY LDC Average	143,638	$ 165,107,528	$ 22,395,262	$ 1,257	$ 167	129,958	$ 68,160,153	$ 567

Source: Most Recent FERC Reports, KPSC Website

39

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 39
Witness: David H. Doggette

Data Request:

39. Refer to the response to the Commission's August 19, 1999 Order, Item 19.

a. In response to Item 19(d), Western states that it is not required to maintain records documenting capital project budgeted starting and ending dates nor capital project actual starting and ending dates. Based on this response, does Western mean that it does not keep any information concerning the starting or ending dates for its individual capital projects? Explain the response.

b. Would Western agree that the maintenance of such capital project information would be a sound business practice? Explain the response.

c. In response to Item 19(e), Western states that it does not record whether a capital project is completed ahead of schedule, on schedule, or behind schedule. Explain in detail why Western does not record such information. Also explain whether Western would agree that the recording of such information would be a sound business practice.

d. In the response to Item 20 of this data request, Western has stated that all capital projects were completed in the fiscal year in which they were budgeted. If Western does not record information concerning the beginning and ending construction dates or information on whether the project was completed on schedule, explain in detail how Western can conclude that all capital projects are completed within the fiscal year they were budgeted.

Response:

a. No. Western does, during the approval process for capital projects, indicate an anticipated starting and ending date. The completion date is indicated on the project completion sheet. Western does not have a separate report for maintaining such information.

b. No. Western has no need for this information after the fact. Western believes that capital project information regarding safety and fiscal responsibility are more relative.

c. Western has no need for this information after the fact. Western does indicate the completion date on the project completion form. Western believes that evaluation of the project with relation to safety and budgeted dollars are more important measures.

d.. Western concludes all capital spending for a fiscal year at the end of each September. The capital budgeting system would have been closed at the end of the fiscal year. Projects are started with sufficient time allowed for completion prior to the end of the fiscal year. Toward the end of the fiscal year only construction of a minor nature is done. Funding for this work is drawn from blanket projects such as short main extensions or service line installations. Again, these are completed before the end of September so the blanket project can be closed. If blanket work cannot be completed in time for the year-end closing, it is delayed until the start of the new fiscal year and drawn against the funding for such projects in the new fiscal year.

40

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 40
Witness: David H. Doggette

Data Request:

40. Concerning Western's capital projects included in the base and forecasted periods.

a. Western has assumed that the budgeted amounts for the capital projects and the final actual expenditure for those projects will be the same. Explain in detail why this is a reasonable assumption.

b. When determining the amounts to recognize for its budgeted capital projects in the estimated portion of the base period or in the forecasted period, does Western agree that it would be reasonable to adjust the budgeted amounts, using the historic completion percentage, in order to more accurately reflect actual expected capital additions? Explain the response.

Response:

a. Western incorporates all known and measurable factors at the time of budgeting and therefore anticipates the budgeted amount to be the true and expected cost(s) for those projects.

b. No. Once again Western incorporates all known and measurable factors, reasonably anticipated to affect capital spending, at the time of budget preparation, including prior actual costs. Historical factors that caused budgeting fluctuations may not accurately reflect or affect the projects proposed for that budget year.

41

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 41
Witness: David H. Doggette

Data Request:

41. Refer to the response to the Commission's July 16, 1999 Order, Item 28, and the August 19, 1999 Order, Item 18.

a. In five of the eight fiscal years that Western reported capital budget project information for the WKG Company Office operating area, the expenditure amount exceeded the budget amount. For those eight fiscal years, the WKG Company Office's total of all expenditures exceeded the total of all budgeted amounts by approximately 163 percent. Explain in detail why actual capital project expenditures have been exceeding the capital budgets for this operating area.

b. In seven of the nine fiscal years that Western reported capital budget project information for the Owensboro Operations operating area, the expenditure amount exceeded the budget amount. For those nine fiscal years the Owensboro Operations' total of all expenditures exceeded the total of all budgeted amounts by approximately 114 percent. Explain in detail why actual capital project expenditures have been exceeding the capital budgets for this operating area.

Response:

a. The WKG Company Office budget center covers the General Office at Western and normally has a relatively small capital budget, approximately 1% of Western's total budget. Any item of significance that is approved for expenditure above the budgeted level results in being a significant percentage over budget, even thought the dollar amount of the over-budget expenditure is very small relative to the overall WKG budget. Unforeseen needs that affected several budget centers may have been against this budget center during the earlier years of the period.

b. New main and service installation costs exceeded budget because requests for service exceeded normal expectations.

42

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item # 42
Witness: Rebecca M. Buchanan

Data Request:

42. Refer to the response to the Commission's August 19, 1999 Order, Item 21(a). Western was requested to provide a summary for pages 1 through 4 of 6 of Exhibit DHD-1, listing the additions by plant account number. The summary was to also show how amounts for retirements and public works reimbursements were allocated to the particular plant accounts. Western's response, which included citations to workpapers "B-2 B 09" and "B-2 F 09," does not adequately address the question, in that the cited workpapers do not show how the amounts for retirements and public works reimbursement were allocated to the plant accounts. Provide the information originally requested.

Response:

42.) Please refer to Western's response to the Commission's August 19, 1999 Order, Item 21(a), a copy of which has been attached to this response. Western's citation to workpapers "B-2 B 09" and "B-2 F 09," was included in the response to 21(a) to convey general information. Western wants the Commission to know that although Exhibit DHD-1 did not assign the "retirements" and "public works reimbursements," to plant accounts, they were properly assigned to plant accounts in the rate base workpapers cited. The citation was not meant to be the part of the response that showed how the amounts were assigned to specific asset accounts. Western's response did not stop at that citation. The two sentences that follow the workpaper citation are also part of the response to 21(a).

Western's response to Item 21(a) answers the question by showing the specific plant accounts to which the retirements and public works reimbursements were assigned. (For convenience, please refer to the copy attached). For fiscal year 1999, the account assignment is shown on the worksheet that is included as the final attachment to that response. For fiscal years 2000 and 2001, the account assignment is provided in a sentence that begins at the bottom of the first page of the response and concludes at the top of the second page. Brackets appear in the left and right margins of the attached copy to guide the reader to the place in the response where the plant account is provided (376 Mains).

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #2 Dated August 19, 1999
DR Item 21
Witness: Rebecca M. Buchanan

Data Request:

21. Refer to the response to Item 35 of the Commission's July 16, 1999 Order. The response provides the link between the capital budget projects shown in Volume 3 of 10, Tab 1, Exhibit DHD-1 with Volume 10 of 10, Tab 2, Schedule B-2.2. However, this link applies only to the grand totals from Exhibit DHD-1. A link between the additions to a particular plant account cannot readily be established.

a. For pages 1 through 4 of 6 of Exhibit DHD-1, provide a summary for each page listing the additions by plant account number, rather than budget categories. Retain the column titles showing the expenditure classifications for each page. Also show how the amounts for retirements and public works reimbursements are allocated to the particular plant accounts.

b. For any asset account shown on Schedule B-2.2, for either the base period or forecasted period, explain in detail why the addition shown does not match the plant account summary provided in response to part (a) above.

Response:

21a.) Please refer to Exhibit DHD-1 shown in Volume 3 of 10, Tab 1. On each of the pages 1 through 4 of 6, the second column titled "Acct #" provides the plant account number for each addition.

With regard to retirements (more accurately described as cost of abandonment, as explained by Mr. Doggette in his response to KPSC DR set 1, item #35c, dated July 16, 1999) and public works reimbursements, Exhibit DHD-1 does not provide the associated plant accounts. However, workpapers WP B-2 B 09 and WP B-2 F 09, found in Volume 10, Tab 15 of the filing, do apply the "retirements" and public works reimbursements to the detail plant accounts. For the fiscal years 2000 and 2001, line 41 of Exhibit DHD-1 "Retirements" and line 72 of Exhibit DHD-1 "Public Works Reimbursements" are included in account 376 Mains. For fiscal year 1999, the account distribution for lines 41 and 72 is provided on the attachment titled "Fiscal Year 1999 Capital Budget – Retirements/Salvage & Removal and Public Works Reimbursements."

21b.) There are several reasons why the additions shown on Schedule B-2.2 will not match those shown in Exhibit DHD-1. Please refer to Western's response to KPSC DR set 1, item 35a, 43 and 44. In reading these responses, you will find that the capital budget additions on DHD-1 make up only part of the additions that finally flow through the workpapers to Schedule B-2.2. Western's response to KPSC DR set 1, items 43 and 44 explains the source of each component of the Western Division 09 base year and fiscal year capital additions. Also, as explained in the response to KPSC DR set 1, items 35a, an allocated portion (16.657%) of the Division 02 General Office capital budget additions are included in Schedule B-2.2. These are not shown on DHD-1.

Another fact to keep in mind is that for the Base Period, it is the net additions, retirements and transfers on Schedule B-2.2, pages 1-3 of 6 that tie back to the budgeted additions in the supporting workpapers and documentation.

If the focus of Staff's request is the budgeted capital additions shown in DHD-1, and how these additions are assigned to the specific asset accounts, there are slight variations in the account assignments between DHD-1 and workpapers WP B-2 B 09 & WP B-2 F 09, and eventually Schedule B-2.2. These variations are mainly attributed to the line items 41 "retirements" and 72 "public works reimbursements" on Exhibit DHD-1 not being assigned to the asset accounts on this exhibit (see response to 21a above). Another difference is that for fiscal years 2000 and 2001, the additions for the asset accounts 399.86 "PC Hardware" and 399.87 "PC Software" were entered on the wrong lines of workpaper WP B-2 F 09. These were mistakenly entered on the next lower line respectively as 399.87 "PC Software" and 399.88 "Application Software." This mistake caused depreciation expense to be understated by approximately $2,000, which is immaterial. Finally, there were slight variations in how inflation and overhead rates were applied and to how line 79 "Forfeitures" (asset account 376 Mains) was handled on DHD-1 as compared to on the workpapers WP B-2 B 09 & WP B-2 F 09.

If "retirements" and "public works reimbursements" are properly assigned on DHD-1, then the remaining percentage variation in the account assignment for the budgeted capital additions averages 2 % in fiscal year 1999, 0% in fiscal year 2000 and 2% in fiscal year 2001.

response to KPSC DR set 3, Item #42
Attachment sheet 4

response to KPSC DR #2
Item #21 a.

Western Kentucky Gas Company
KPSC Case No. 99-070
Fiscal Year 1999 Capital Budget
Retirements/Salvage & Removal and Public Works Reimbursements

RETIREMENTS / SALVAGE & REMOVAL:	Account# Description	1999 w/o OH	50.425% OH	1999 incl. OH
1	351.20 Compression Station Equipment	$300	$151	$451
2	352.02 Well Equipment	25,900	13,060	38,960
3	367.00 Mains - Steel	1,280	645	1,925
4	376.00 Mains - Cathodic Protection	100	50	150
5	376.00 Mains - Steel	26,960	13,595	40,555
6	376.00 Mains - Plastic	11,897	5,999	17,896
7	378.00 Meas. & Reg. Sta. Equipment General	3,200	1,614	4,814
8	379.30 Meas. & Reg. Sta. Equipment Town Border	502	253	755
9	380.00 Services	197,386	99,532	296,918
10	381.00 Meters	7,770	3,918	11,688
11	382.00 Meter Installation	41,284	20,817	62,101
12	383.00 Regulators Service	100	50	150
13	385.10 Ind. Meas. & Reg. Sta. Equipment	2,800	1,412	4,212
14	390.09 Improvements - Leased Premises	1	1	2
15	Total	**$319,480**	**$161,098**	**$480,578**

PUBLIC WORKS REIMBURSEMENTS:	Account# Description	Amount		
16	376.00 Mains - Cathodic Protection	($90,148)	(45,457)	(135,605)
17	376.00 Mains - Steel	(63,830)	(32,186)	(96,016)
18	376.00 Mains - Plastic	(10,201)	(5,144)	(15,345)
19	385.10 Industrial Measuring and Reg. Sta. Equip.	(26,400)	(13,312)	(39,712)
20	Total	**($190,579)**	**($96,099)**	**($286,678)**

43

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item # 43
Witness: David H. Doggette & Rebecca M. Buchanan

Data Request:

43. Refer to the response to the Commission's August 19, 1999 Order, Item 21(b).

a. In this response, Western states "These variations are mainly attributed to the line items 41 'retirements' and 72 'public works retirements' on Exhibit DHD-1 not being assigned to the asset accounts on this exhibit." Explain in detail what asset accounts line items 41 and 72 were being assigned to if not Exhibit DHD-1.

b. If line items 41 and 72 were not being assigned to asset accounts on Exhibit DHD-1, explain why these line items were included on Exhibit DHD-1 originally.

c. In this response, Western states "Finally, there were slight variations in how inflation and overhead rates were applied and to how line 79 'Forfeitures' (asset account 376 Mains) was handled on DHD-1 as compared to on the workpapers WP B-2 B 09 and WP B-2 F 09." Explain in detail the nature of the "slight variations" referenced in this response. Also explain why Western would handle the Forfeitures amount differently.

Response:

43 a. & b.) The main purpose of Exhibit DHD-1 was to show the capital budget by category. The account # column was added as a final step to "assist" in the internal development of the rate base workpapers. Because "retirements" and "public works reimbursements" are assigned to "various" plant accounts in fiscal year 1999, the word "various" was typed into the account # field on DHD-1. Perhaps the word "numerous" or "several" would be a better term to have used. "Retirements" and "public works reimbursements" are proper items to include in the Capital Budget Forecast. A separate worksheet was used to show the specific account assignments for these two lines. This worksheet was included in response to the Commission's August 19, 1999

Order, Item 21(a), and again as an attachment to the response to the Commissions September 20, 1999 Order, Item 42 above.

43c.) In the response to the Commission's August 19, 1999 Order, Item 21(b), Western states "Finally, there were slight variations in how inflation and overhead rates were applied and to how line 79 'Forfeitures' (asset account 376 Mains) was handled on DHD-1 as compared to on the workpapers WP B-2 B 09 and WP B-2 F 09." Mr. Doggette developed the Capital Budget Forecast, which is filing requirement FR 10(9)(b), found in Volume3, Tab 1, Exhibit DHD-1. It was the intention of Ms. Buchanan, in preparing the rate base workpapers WP B-2 (Volume 10, Tab 15), to use the same methodology as Mr. Doggette in applying overhead rates to Western's direct additions. For fiscal year 1999, Ms. Buchanan started with Mr. Doggette's detail direct additions of $5,461,802. It was understood by both Mr. Doggette and Ms. Buchanan that the overhead dollars should total approximately $2,946,000. In order to achieve this level of overhead, Ms. Buchanan determined that a rate of 53.94% would need to be applied to each asset account's budgeted additions. Mr. Doggette applied an overhead rate of 50.425% to the budgeted direct additions on DHD-1, excluding Forfeitures, to arrive at approximately $2,946,000 overhead. Ms. Buchanan was not aware that Forfeitures should not have had overhead applied. The variation in applying overhead to Forfeitures caused each of the line item fiscal year 1999 budgeted additions on WP B-2 to be 2.3% greater than on DHD-1, except for Mains account 376. For 376 Mains, WP B-2 was 4.2% less than the amount shown on DHD-1. Because the variances are offsetting, the budgeted additions for fiscal year 1999 on WP B-2 agree in total with DHD-1.

There were no variations between DHD-1 and WP B-2 for fiscal year 2000, as both apply 50% overhead to all line items except Forfeitures.

It was understood by both Mr. Doggette & Ms. Buchanan that the fiscal year 2000 budget would be the basis of the fiscal year 2001 budget. Inflation and overhead rates would be applied to each line item of the fiscal year 2000 budget to arrive at total capital budget additions for fiscal year 2001 of $9,786,414. Ms. Buchanan started with the fiscal year 2000 direct additions, applied 50% overhead to all line items, with the exception of Forfeitures in account 376 Mains, which brought the total to $9,696,372. Because of the different approaches that Mr. Doggette and Ms. Buchanan used, Ms. Buchanan applied a reconciling factor of approximately 1% to each line item to arrive at the 2001 total budget amount of $9,786,413.

In the process of responding to the Commission's August 19, 1999 Order, Item 21(b), a closer look at DHD-1 revealed that Mr. Doggette had inadvertently applied overhead to the line item Forfeitures on page 4 of 6. As noted in the preceding paragraph, Ms. Buchanan treated fiscal year 2001 Forfeitures the same as in fiscal year 2000; that is, she did not apply overhead to Forfeitures. The variation in applying overhead to Forfeitures caused each of the line item fiscal year 2001 budgeted additions on WP B-2 to be 2% less than on DHD-1, except for Mains account 376. For 376 Mains, WP B-2 was 2.7% more than the amount shown on DHD-1. Because the variances are offsetting, the budgeted additions for fiscal year 2001 on WP B-2 agree in total with DHD-1.

Western did not intentionally handle Forfeitures differently between the two documents DHD-1 and WP B-2. The variances caused by this oversight are slight and do not materially misstate Western's rate base or cost of service.

44

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item # 44
Witness: David H. Doggette & Rebecca M. Buchanan

Data Request:

44. Refer to the response to the Commission's August 19, 1999 Order, Item 22. It appears that the estimated monthly plant account additions result from a determination of the total increase, which is then divided into equal amounts to be added during the base or forecasted periods.

a. Explain in detail why Western believes this to be a reasonable method to recognize the estimated additions to its utility plant accounts.

b. Does the approach described by Western in this response represent its normal method of reflecting estimated plant additions as part of its normal budgetary process? Explain the response.

c. Explain why Western did not recognize seasonal factors when determining when to record the estimated plant additions.

Response:

44a.) With regard to how the estimated monthly plant additions were determined, in the base period it was known that a $19,235,840 would be added to Western's plant in service in April 1999, therefore these assets were placed in service in the rate base workpapers in the month of April 1999. The remainder of the budgeted additions for the base period and the forecasted test period were annual budgeted additions. The capital budget forecast is not developed to show which months the additions might be closed to plant, except the assurance that all projects budgeted in a fiscal year were expected to be closed in that same year. Given these facts, it is reasonable to estimate the monthly additions by spreading the annual amount evenly over the year.

44b.) The method of spreading the annual capital budget additions evenly over each month in the fiscal year is the approach used to facilitate the preparation of the rate base workpapers referenced in response to the Commission's August 19, 1999 Order, Item 22. Western does not use this approach as part of its annual budgetary process. Western has attempted to estimate monthly capital additions for other long range planning purposes, other than the annual budgetary process. The effect of weather on construction schedules was factored into the estimates. When compared to the actual plant closings, these monthly estimates were not accurate. Unseasonably mild winters allowed for the completion of projects earlier than estimated.

44c.) Western did not recognize seasonal factors when determining when to record the estimated plant additions in the rate base workpapers because, as explained in 44b. above, the effects of weather are unpredictable. Additionally, the use of a thirteen month average rate base minimizes the impact that any seasonal adjustments might have on total rate base. Finally, Western incorporates a half year convention for calculating booked depreciation - estimating monthly or seasonal plant additions is not necessary in order to budget for depreciation expense under this convention.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 45
Witness: Buchanan & Burman

Data Request:

45. Refer to the response to the Commission's August 19, 1999 Order, Item 23.

a. In the response to Item 23(a), Western stated that the depreciation allocation problem in the original base period was due to a misallocation of the reserve balances that occurred prior to 1996. Explain how and when Western determined that there had been a misallocation of the depreciation reserve balances.

b. In the same response, Western states that the major category accumulated depreciation balance was spread among the individual accounts within the specific category pro-rata, according to the related plant investment balance as compared to the total investment for that asset category at September 30, 1998. Explain how and when Western determined this was the appropriate methodology to use when allocating the accumulated depreciation balance to individual accounts.

c. Concerning the allocation of the accumulated depreciation balance, explain in detail why Western's approach is reasonable.

d. Under Western's allocation of the accumulated depreciation balance, doesn't this approach eliminate the possibility that Western could have over-depreciated an asset group? Explain the response.

Response:

45a.) The depreciation misallocation was brought to the Company's attention by the Commission upon our review of DR Item 37 of the Commission's July 16, 1999 Order.

45b.) In the process of responding to Item 37 of the Commission's July 16, 1999 Order it was determined that the method of allocation chosen by the Company provided a systematic and rational method of allocating the accumulated reserve.

45c.) The approach chosen provided a systematic and rational approach while not having the benefit of a vintage year for all additions, retirements, transfers and adjustments on a plant account basis from the start of business of the Company. It is the belief of the Company that all methods of allocation would likewise necessitate the use of estimates and assumptions rendering them somewhat subjective.

45d.) This method of allocation does not eliminate the possibility of over-depreciation of an individual asset group. If the total of the reserve by group is greater than the total of the assets by group each account would result in a negative balance. The accumulated reserve records of the Company are not kept on a plant account basis. It is the belief of the Company that no accounts are over-depreciated.

46

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 46
Witness: Gruber

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 24(e). The response to this request was inadequate. For each of the consulting services described below, explain in detail why the associated costs have been included as part of the rate case expenses.

a. October 20, 1998 – Met with West Kentucky Gas to discuss . . . other PSC related activities.

b. November 20, 1998 – Reviewed Court decision and agreement with Hopkinsville concerning franchise tax.

c. December 18, 1998 – Reviewed information on CIAC and discussed with PSC Staff.

d. December 23, 1998 – Continued to work on CIAC.

e. March 1, 1999 – Work on testimony.

f. April 20, 1999 – Work on testimony.

Response:

a. This was Mr. Sharpe's first meeting with Western on its rate case. The reference on Mr. Sharpe's invoice ("other PSC related activities") pertains to discussions related to KPSC filing requirements, rate case rules and process, precedents, recent decisions, and rate case related activity regarding companies other than Western pending at that time. Such information, Mr. Sharpe's knowledge and experience regarding Kentucky regulatory matters, and his expertise on utility ratemaking and economics was valuable to Western in its rate case planning.

b. This reference pertains to research Mr. Sharpe was conducting related to inclusion of the Hopkinsville franchise fee as a cost of service in this case as a means of cost recovery. The franchise settlement between Western and Hopkinsville, as result of a court decision, prohibited Western from recovering this cost as an item on the bill collected exclusively from Hopkinsville customers. Mr. Sharpe's research was valuable to Western in its rate case planning.

c., d. These references pertain to research and input provided by Mr. Sharpe related to the KPSC's regulations on main extensions and contributions in aid of construction (CIAC). This was part of Western's overall research in support of an incremental cost study and proposed Premises Charge in this case, a component of which addresses CIAC. Mr. Sharpe's research and input was valuable to Western in its rate case planning.

e.,f. These references relate to Mr. Sharpe's review and consultation regarding drafts of the testimony filed in this case. The response to KPSC #1 – DR 39a indicates that Mr. Sharpe began work in this capacity in February 1999 and continued throughout the preparation of the case. Mr. Sharpe's input was valuable to Western in the preparation of its rate case testimony.

47

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 47
Witness: Gruber

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 24(f). Provide a description of the "certain matters" that the firm of Ward and Anderson provided legal research in conjunction with this rate case.

Response:

Ward and Anderson performed legal research on behalf of WKG researching precedents at the Federal Energy Regulatory Commission that WKG evaluated in preparing the filing of this case. This research included review of any possible changes in federal law or regulations that may impact WKG's filing or its business activities.

48

Western Kentucky Gas Company
Case No. 99-070
KPSC Dated Request #3 Dated September 20, 1999
DR Item 48
Witness: Betty Adams

Data Request:

Refer to the response to the Commission's August 19, 1999 Order, Item 28. For the organizations listed in parts (c), (d), (e), and (g), provide a description of the nature of the organization, a listing of the benefits Western receives from being a member, and a description of the education and training programs that Western employees have attended within the last two years that have been sponsored by the organization.

Response:

Nature of the Organization (American Gas Cooling Center) - The natural gas industry has made sizable investments into developing gas cooling markets because they offer numerous advantages. Gas cooling markets have the potential to improve gas utility revenue by increasing off-peak usage and by more-fully utilizing existing gas utility distribution assets. Gas cooling offers opportunity to reduce overall energy consumption and emissions associated with space conditioning, process cooling and refrigeration. Cooling and refrigeration markets are currently dominated by electric technologies.

Listing of Benefits Associated from Being a Member (American Gas Cooling Center, AGCC) - The mission of the AGCC is "to develop sustainable and profitable gas cooling, refrigeration and dehumidification markets that increase throughput on gas distribution systems and reduce overall energy consumption and emissions associated with space conditioning and refrigeration." Western Kentucky Gas Company's relationship with the AGCC offers an opportunity for influencing the use of gas cooling equipment in larger tonnages. The projected increases in peak-day prices for electricity in many markets favorably position hybrid gas/electric cooling systems. Further, customer demands for reduced operating expenses provide opportunities for lower operating cost gas cooling systems. More stringent environmental regulations position natural gas positively when evaluated on a full-cycle emissions basis and bans on CFC usage favor non-CFC gas cooling systems. The Federal government's acknowledgement of the value of Total Energy Efficiency provides opportunity for natural gas cooling and integrated system solutions. Western Kentucky Gas Company must pursue relationships with associations with organizations like the AGCC when natural gas could provide cost-saving opportunities to our customers. Not only would this use of natural gas increase our market share in these defined markets, there would also present advantages for our customers.

Description of the Education and Training Programs Western Kentucky Gas Company Employees Have Attended Within the Last Two Years Sponsored by the American Gas Cooling Center (AGCC) - WKG has benefited from attending the Natural Gas Cooling Conference. This annual conference sponsored by the AGCC provides an opportunity for those from the natural gas industry as well as Architects, Engineers and HVAC Contractors to learn of the latest developments and view demonstrations of natural gas cooling equipment and technologies.

Nature of the Organization (Southern Gas Association, SGA) - The SGA serves the interest of 138 natural gas distribution, transmission and gas marketer companies in 17 southern states. Member distribution companies serve 25 percent of the nation's consumers; member transmission companies transport 80 percent of the interstate natural gas used nationally.

<u>Listing of Benefits Associated from Being a Member (Southern Gas Association, SGA)</u> - The SGA offers educational opportunities for members that include; newsletters, monthly telecom training/information programs, natural gas research/informative data and scheduled conferences across the Southern United States regarding developments and all facets of the natural gas industry. The SGA, along with the American Gas Association, serves as a clearinghouse for information/data on our industry. Private companies and municipalities alike support the SGA as their avenue to information, education/training and technical assistance in providing natural gas, the fuel of choice in most energy markets.

<u>Description of the Education and Training Programs Western Kentucky Gas Company Employees Have Attended Within the Last Two Years Sponsored by the Southern Gas Association (SGA):</u>

- Industrial Marketing Roundtable - Panel discussion on Retail Unbundling, Business Impact of Customer Service and Power Generation Opportunities and Industrial Marketing.
- Capital Budget Analysis and Valuation - Group discussion and strategies among natural gas distribution/transmission companies concerning budgeting and valuation practices for the 21st Century.
- Natural Gas Training Conference - Information/ideas exchange dealing with training methods and strategies for employee development and compliance issues.
- Distribution Roundtable/Engineers - Discussion of engineering and operations issues encountered and resolved by attending natural gas companies.
- Distribution Operating Conference - Technical presentations on volume corrector communications in hazardous areas, reducing noise levels and maintenance in pressure regulation equipment, expanding field order applications and improved productivity through the use of advanced pipe coil trailers. Also discussed were collecting procedures, use of contractors, line maintenance, deregulation, operating structure, customer service, call center operations and employee training.
- 21st Century Leadership Training - "Shaping the Environment" - This conference covered visioning, planning and dealing with organizational change. Also discussed were dealing with customers, providing opportunities for leadership and effective leadership.
- Communications Conference - Discussions about the latest trends and ideas for communicating with external and external customers.

<u>Nature of the Organization (American Gas Association, AGA)</u> - The AGA represents 189 local natural gas utilities that deliver gas to 54 million homes and businesses in all fifty states. Additionally, the AGA provides services to member natural gas pipelines, marketers, gatherers, international gas companies and a variety of industry associates. The AGA acts as a clearinghouse for gas energy information for the public, government an industry. It also provides technical information in energy policy matters.

<u>Listing of Benefits Associated from Being a Member (American Gas Association, AGA)</u> - The AGA, like the SGA, offers educational opportunities for members that include; newsletters, natural gas research/informative data and scheduled conferences across the United States regarding all facets of the natural gas industry. The AGA serves as a clearinghouse for information/data to/for our industry. Private companies and municipalities across the United States support the AGA as their avenue to information, education/training and technical assistance in providing natural gas, the fuel of choice in most energy markets.

Description of the Education and Training Programs Western Kentucky Gas Company Employees Have Attended Within the Last Two Years Sponsored by the American Gas Association (AGA):

- Customer Satisfaction Management Benchmarking Study - A study with the participation of 27 AGA member companies identifying how they managed their customer satisfaction issues. They also surveyed several companies outside the natural gas industry to help identify "best practices" for customer service.
- "Betting on Our Customers" - This conference involved the AGA Marketing and Communications Committees and centered around residential marketing and customer service.

Nature of the Organization (Institute of Gas Technology, IGT) - The IGT is an independent, not-for-profit center for energy and environmental research, development, education, and information. Founded in 1941, its main functions are to perform sponsored and in-house research, development, and demonstration; provide educational programs and services; and disseminate scientific and technical information.

IGT conducts research primarily in four areas: energy utilization, energy supply, environmental protection and remediation, and natural gas transmission, distribution and operations. They also offer seminars, conferences, symposia, video-based training and home-study and classroom courses.

Listing of Benefits Associated from Being a Member (Institute of Gas Technology, IGT) - The IGT provides gas companies with the largest, single depository for natural-gas specific information in our industry. The IGT is a ready resource to gas companies for information.

Description of the Education and Training Programs Western Kentucky Gas Company Employees Have Attended Within the Last Two Years Sponsored by the Institute of Gas Technology (IGT): Western employees have not attended education and training programs sponsored by the IGT during the last two years. We do benefit from our membership and association with this organization for the obvious reasons described above. Natural gas research and development is necessary to better serve existing and future natural gas end users.

49

Western Kentucky Gas Company
Case No. 99-070
KPSC Dated Request #3 Dated September 20, 1999
DR Item 49
Witness: Betty Adams

Data Request:

Refer to the filing requirements at Volume 10 of 10 of the Application, Tab 6, Exhibit FR 10(10)(f), Schedule F-1, Pages 1 through 6, membership dues for the base period and forecasted test year. Explain the nature of the organizations and why the membership dues should be included for ratemaking purposes.

a. Club or organization from the base period - Associated Industries of KY, Ky., Labor-Management Conference, Green River Home Builders Association, Owensboro Home Builders Association, Hopkins County Home Builders, Henderson Home Builders, Association of U.S. Army, Hopkinsville Home Builders, Military Affairs Committee, Paducah Home Builders, Builders Association of Bowling Green, Russellville Home Builders, Danville-Boyle County Home Builders, Kiwanis Club, Lions Club and Civitan Club.

b. Club or organization from the forecasted test year - Associated Industries of KY, Ky., Labor-Management Conference, Green River Home Builders Association, Owensboro Home Builders Association, Hopkins County Home Builders, Henderson Home Builders, Association of U.S. Army, Hopkinsville Home Builders, Military Affairs Committee, Paducah Home Builders, Builders Association of Bowling Green, Russellville Home Builders, Danville-Boyle County Home Builders, Kiwanis Club, Lions Club and Civitan Club.

Response:

a. & b. **Nature of the Organizations (Home Builder Associations)** - Green River Home Builders, Owensboro Home Builders, Hopkins County Home Builders, Henderson Home Builders, Hopkinsville Home Builders, Paducah Home Builders, Builders Association of Bowling Green, Russellville Home Builders and Danville-Boyle County Home Builders.

Local Home Builder Associations hold monthly general membership meetings to provide its members an opportunity to exchange ideas and information. They feature topics of interest to the building trade at each monthly meeting. These organizations promote the housing industry and continually strive to provide quality housing. They assist members in promoting their services through home shows, table-top nights and parade of homes. Home Builders Associations host educational seminars on a variety of subjects to help in keeping the local housing industry affordable and functional. These associations stay alert to local government involvement to obtain good laws, including zoning, building codes or subdivision regulations. Association members are active in many volunteer, civic services which better serves the communities in which they operate.

Why the membership dues (Home Builder Associations) should be included for ratemaking purposes - These associations present Western Kentucky Gas Company a low cost/high benefit way to stay involved with local housing professionals who are providing functional, quality and affordable housing opportunities for our current and future customers. This relationship allows us to educate and inform Home Builders of how natural gas can be used as a clean burning, efficient energy source in the housing industry throughout our service territory. Further, these associations offer Western Kentucky Gas Company an avenue to define natural gas as the efficient energy source for the housing market which will in turn better benefit all existing or future customers of Western Kentucky Gas Company. It is important for Western to know what organizations like the Home Builders plans are so that we can share our plans and act accordingly.

Nature of the Organization (Associated Industries of KY, Ky.- AIK) - AIK is a statewide association dedicated to a better business, tax and labor climate. Founded in 1911, AIK is the largest pro-business group in Kentucky covering all segments of the business community. This organization, through its efforts, defines Kentucky as an attractive state in which to locate industry and to raise a family. AIK has for many years been instrumental in presenting Kentucky as a friendly business climate. AIK annually hosts seminars on all facets of the business climate. Further, their public awareness programs help make students, parents, educators and opinion leaders aware of the many opportunities available in Kentucky's manufacturing skilled trades careers.

Why the membership dues (Associated Industries of Kentucky, Ky. - AIK) should be included for ratemaking purposes - A better business, tax and labor climate certainly benefits Kentucky, Western Kentucky Gas Company and our 178,000 customers. Educating all that Kentucky is a state in which to locate business and to raise families will help make this state's economic success and the success of its residents a reality. Western Kentucky Gas Company considers that partnering with entities like AIK is an efficient way to share information and to invest in the future of our customers and our business. This relationship helps to ensure a growing Kentucky that will provide our customers and their families with growth opportunities today and well into the future.

Nature of the Organization (Labor-Management Conference) -The Kentucky Labor-Management Conference, Inc. is a nonprofit, nonstock corporation duly authorized to carry on business in Kentucky. The general purpose of this corporation is to promote positive labor-management relations in the workplace, specifically by holding a conference annually, entitled "The Labor-Management Conference." This conference offers educational opportunities in the form of seminars and discussions designed to educate everyone as to the concept of labor-management cooperation in various communities and businesses throughout the Commonwealth.

Why the membership dues (Labor-Management Conference) should be included for ratemaking purposes - Supporting a favorable labor-management climate is paramount for preparing Kentucky for continued economic growth. Economic growth for our state in turn helps to ensure a better life for Kentucky residents and customers of Western Kentucky Gas Company. Western, along with most constituents involved in business in this State, share in the responsibility for supporting such endeavors. A positive labor-management climate encourages economic growth and reflects a positive business atmosphere to those outside the State.

Nature of the Organization (Association of the United States Army - AUSA) - The AUSA is a private, non-profit, educational organization whose members, civilian and military, support all aspects of national security with emphasis on America's Total Army and the men and women who serve. One of this association's objectives is public education, along with people support for those in the Army: Active Duty, Reserves, National Guard, DA civilians, the retired and their families. The AUSA has 6,000 corporate members (companies) around the world who support the Army and AUSA's Mission of Keeping America's Army Strong!

Why the membership dues (Association of the United States Army - AUSA) should be included for ratemaking purposes - Many of Western Kentucky Gas Company's customers are employed by the U.S. Army and the organizations described above. In particular, our service area in Hopkinsville is predominantly dependent on the presence of the military installation, Fort Campbell. Additionally, there are numerous Army Reserve and National Guard Units located in our service area. Participating in military related/community programs is expected and appropriate in our service area. Our support of national defense efforts throughout our service territory and the Commonwealth is a responsibility that we willingly share with many Kentucky corporations. We recognize that we are not only supporting the success of the AUSA, but we are supporting the livelihood of many of our customers. These military organizations are essential in our country's response to any national defense crisis.

Nature of the Organization (Military Affairs Committee) - The mission of the Military Affairs Committee is "to plan, coördinate and execute programming and activities which will strengthen the relationship between Hopkinsville and Fort Campbell and bring about a heightened awareness of one community's importance to the other. In doing so, we hope to attract both active and retired military to make Hopkinsville their permanent home."

Why the membership dues (Military Affairs Committee) should be included for ratemaking purposes - Providing efficient, quality natural gas service to our customers in the Hopkinsville area is of primary importance to Western Kentucky Gas Company. It stands to reason that supporting the success of one the primary employers in the Hopkinsville community is also of major importance to our Company. A large portion of our customer base in the Hopkinsville area is employed by and for companies that are in the U.S. Army or are a support company to the military. Participating in military related/community programs is expected and appropriate in our service area. Our support of national defense efforts throughout our service territory and the Commonwealth is a responsibility that we willingly share with many Kentucky corporations. We recognize that we are not only supporting the success of the Armed Forces, but we are supporting the livelihood of many of our customers. These military organizations are essential in our country's response to any national defense crisis.

Nature of the Organization (Kiwanis Club) - The Kiwanis Club is a local and national non-profit organization. The organization is made up of local business people throughout the United States. Kiwanis goals are to provide support to each community through fund raising efforts that consistent with the club's existence. Kiwanis provides scholarships, special funds for local projects and in particular, the IDD, which stands for Iodine Deficiency Disorders. Kiwanis organizations exist throughout Western Kentucky Gas Company's service territory.

Why the membership dues (Kiwanis Club) should be included for ratemaking purposes - The Kiwanis Club epitomizes community involvement throughout the Commonwealth. Western Kentucky Gas Company believes that as part of our community investment, we should, through financial support and time and talent, back organizations that work to ensure a better way of life for those in the Commonwealth, which includes our customers. Agencies like the Kiwanis Club clearly define what community investment is to a private company.

Nature of the Organization (Lions Club) - The Lions Club was founded in 1917 and is the largest service organization in the world, with 42,375 clubs in 178 countries/geographical areas and with a membership in excess of 1.4 million. The Lions Club International Foundation (LCIF), a charitable arm of the Lions Club, is a public, non-profit, tax-exempt corporation that that promotes human welfare by careful application of contributed funds. The LCIF has three objectives. They sponsor the worldwide support for hospitals, schools and universal needs such as medical research. Second, the Lions Club supports programs that help the underprivileged and disabled gain independence so that they can improve their economic and social well being. Lastly, the LCIF helps to rebuild and restore important programs and services after a natural disaster.

<u>Why the membership dues (Lions Club) should be included for ratemaking purposes</u> - The Lions Club enjoys an excellent reputation of community service throughout the U.S. and the Commonwealth of Kentucky. Again, Western Kentucky Gas Company supports the endeavors of such a service-oriented civic club. Agencies like the Lions Club clearly define what community investment is to a private company.

<u>Nature of the Organization (Civitan Club)</u> - The Civitan Club was founded in 1917. The name Civitan was coined from the phrase "civitas", loosely meaning citizenship. "Builders of Good Citizenship" has been a natural motto for this civic-minded group. Helping crippled has long since been a focus for this remarkable service organization. They have built hospitals, parks and playgrounds. They have also been instrumental in the expansion to helping retarded children. They truly have been instrumental in improving the quality of life for children of adversity.

<u>Why the membership dues (Civitan Club) should be included for ratemaking purposes</u> - Civitan Clubs, like the Kiwanis Clubs and Lions Clubs, exist for the betterment of mankind. Civitan Clubs exist throughout Western Kentucky Gas Company's service territory. In supporting clubs like the Civitan, we further support community investment for the benefit of the needy and the customers we serve.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 50 (a,b,c)
Witness: Betty L. Adams

Data Request:

Refer to the response to the AG's August 19, 1999 Data Request, Item 206. A standard business year includes 52 weeks with 40 hours of regular work time per week. This results in 2,080 hours per year.

a. Explain in detail why Western believes it is reasonable to normalize payroll expenses using 2,088 hours. If Western is proposing 2,088 hours because the year 2000 is a leap year, explain why the normalization should recognize an event that occurs only once every four years.
b. Revise all applicable schedules in this response to include a 2,080 per employee, regular work year. (FR 10(10)(g)).
c. If Western based its payroll hours on the year 2000 being a leap year, explain why it did not also adjust its sales and transportation delivery volumes to reflect an additional day's operations.

Response:

a. Western did not consider the leap year in its budgeting process. For WKG's fiscal year (Oct. '99 through Sept. '00) there are 261 actual workdays (excluding weekends) which equates to 2,088 hours, as do the calendar years 2001, 2002 and 2003. During the calendar year 2000, which is our test year there are only 260 workdays.
b. Attached are the following schedules;
   Revised G-1
   Revised G-2
   Revised G-3
   Revised AG DR 206, Schedule A
   Revised AG DR 206, Schedule B
   Total Payroll Recap – Schedule 1A
   Detail Payroll Sample – Schedule 1B
   Revised Total Payroll Recap – Schedule 2A
   Revised Detail Payroll Sample – Schedule 2B

The last four schedules are presented to verify the elimination of 8 hours per employee. In doing this, we found a mathematical error associated with the timing and calculation of merit increases (see AG1-180), which increased our total payroll by $70,352. Even with this discovery we are not proposing to increase our forecast test year expenses.

c. N/A

Western Kentucky Gas Company
Case No. 99-070
PAYROLL Costs
For the Base Period Twelve Months ended September 30, 1999
For the Forecasted Test Period Twelve 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)(g)
Schedule G-1
Sheet 1 of 1

		Operating Expenses				
Line No.	Description	Total Company Unadjusted $	Jurisdictional %	Base Period Jurisdictional Unadjusted $	Adjustments $	Forecasted Period Jurisdictional ADJUSTED $
1	Payroll Costs					
2	Labor	10,826,198	100.00%	10,826,198	962,529	11,788,727
3	Employee Benefits					
4	PENSION & RETIREMENT Income PLAN	(535,939)	100.00%	(535,939)	1,148,288	612,349
5	Employee INSURANCE PLANS	1,341,697	100.00%	1,341,697	336,295	1,677,992
6	ESOP PLAN Contributions	397,439	100.00%	397,439	23,649	421,088
7			100.00%	0	0	
8	Total Employee BENEFITS	1,203,197		1,203,197	1,508,232	2,711,429
9	Payroll Taxes					
10	F.I.C.A.	823,800	100.00%	823,800	64,023	887,823
11	Federal Unemployment	14,840	100.00%	14,840	951	15,791
12	State Unemployment	6,360	100.00%	6,360	408	6,768
13	Total Payroll Taxes	845,000		845,000	65,382	910,382
14	Total Payroll Costs	12,874,395		12,874,395	2,536,143	15,410,538

Western Kentucky Gas Company
Case No. 99-070
Payroll Analysis by Employee Classifications/Payroll Distribution/Total Company
For the Base Period Twelve Months ended September 30, 1999
For the Forecasted Test Period Twelve 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)(g)
Schedule G-2
Sheet 1 of 1

Line No.	Description	1994	% Change	1995	% Change	1996	% Change	1997	% Change	1998	% Change	Base Period	% Change	Forecasted Period
		Most Recent Five Fiscal Years*												
1	Total Company													
2														
3	Man Hours													
4	Straight Time Hours	809,052	-1.01%	800,858	0.06%	801,307	-2.80%	778,887	-20.23%	621,296	-9.54%	562,029	6.52%	598,669
5	OverTime Hours	26,837	-18.44%	21,888	-38.29%	13,506	-12.67%	11,795	-14.81%	10,048	7.52%	10,804	1.81%	11,000
6	Total Manhours	835,889	-1.57%	822,746	-0.96%	814,813	-2.96%	790,682	-20.15%	631,344	-9.27%	572,833	6.43%	609,669
7	Ratio of OverTime Hours													
8	to Straight-Time Hours	3.317%		2.733%		1.685%		1.514%		1.617%		1.922%		1.837%
9														
10	Labor Dollars													
11	Straight-Time Dollars	11,727,164	3.20%	12,101,878	5.06%	12,713,686	2.97%	13,091,159	-16.82%	10,889,093	-2.81%	10,582,810	9.13%	11,549,539
12	OverTime Dollars	522,433	-13.99%	449,327	-35.02%	291,991	-7.30%	270,686	-10.76%	241,569	0.75%	243,388	-1.73%	239,188
13	Total Labor Dollars	12,249,597	2.46%	12,551,205	3.62%	13,005,677	2.74%	13,361,845	-16.70%	11,130,662	-2.74%	10,826,198	8.89%	11,788,727
14	Ratio of OverTime Dollars													
15	to Straight-Time Dollars	4.455%		3.713%		2.297%		2.068%		2.218%		2.300%		2.071%
16														
17	O&M Labor Dollars	9,078,785	-4.51%	8,669,384	1.20%	8,773,217	1.56%	8,909,796	-15.34%	7,543,357	0.23%	7,561,039	8.79%	8,225,556
18	Ratio of O&M of Labor Dollars													
19	to Total Labor Dollars	74.115%		69.072%		67.457%		66.681%		67.771%		69.840%		69.775%
20														
21	Employee Benefits													
22	Total Employee Benefits	4,706,517	-6.31%	4,409,339	-17.18%	3,651,950	43.35%	5,235,167	-28.16%	3,761,202	-68.01%	1,203,197	125.35%	2,711,429
23	Employee Benefits Expensed	2,797,904	-14.85%	2,382,483	-24.76%	1,792,555	55.74%	2,791,809	-34.43%	1,830,644	-57.22%	783,099	141.59%	1,891,879
24	Ratio of Employee Benefits													
25	Expensed to Total Employee													
26	Benefits	59.447%		54.033%		49.085%		53.328%		48.672%		65.085%		69.774%
27														
28	Payroll Taxes													
29	Total Payroll Taxes	912,730	4.87%	957,219	3.41%	989,891	5.49%	1,044,220	-6.26%	978,859	-13.68%	845,000	7.74%	910,382
30	Payroll Taxes Expensed	693,994	-4.89%	660,041	1.50%	669,955	3.79%	695,335	-8.25%	638,000	-13.91%	549,250	15.65%	635,219
31	Ratio of Payroll Taxes													
32	Expensed to Total Payroll													
33	Taxes	76.035%		68.954%		67.680%		66.589%		65.178%		65.000%		69.775%
34														
35	Employee Levels													
36	Average Employee Levels	387	-0.52%	385	(0)	377	5.31%	397	-25.19%	297	-10.77%	265	6.42%	282
37	Year end Employee Levels	387	-1.03%	383	(0)	374	-3.74%	360	-24.44%	272	-2.57%	265	6.42%	282

* The Payroll System accumulates data most readily on a fiscal year basis(Oct. 1 - Sept. 30) rather than calendar basis.

Western Kentucky Gas Company
Case No. 99-070
Executive Compensation
For the Base Period Twelve Months ended September 30, 1999
For the Forecasted Test Period Twelve 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)(g)
Schedule G-3
Sheet 1 of 1

		Operating Expenses				
Line No.	Description	Base Period Company Unadjusted $	Jurisdictional %	Base Period Jurisdictional Unadjusted $	Adjustments $	Forecasted Period Jurisdictional Adjusted $
1	Includes 8 Officers					
2	Gross Payroll					
3	Salary	743,986	100.00%	743,986	62,862	806,848
4	Other Allowances and Compensation	289,312	100.00%	289,312	(190,378)	98,934
5	Total Salary and Compensation	1,033,298		1,033,298	(127,516)	905,782
6	Employee Benefits					
7	Pensions	(37,964)	100.00%	(37,964)	79,465	41,501
8	Other Benefits	119,527	100.00%	119,527	23,467	142,994
9	Total Employee Benefits	81,563		81,563	102,932	184,495
10	Payroll Taxes					
11	F.I.C.A.	52,511	100.00%	52,511	(4,802)	47,709
12	Federal Unemployment	504	100.00%	504	(56)	448
13	State Unemployment	124	100.00%	124	(24)	100
14	Total Payroll Taxes	53,139		53,139	(4,882)	48,257
15	Total Compensation	1,168,000		1,168,000	(29,466)	1,138,534

NOTE: This schedule contains confidential information, detail of these numbers are available upon request.

DATA REQUEST 206
SCHEDULE A

FORECAST YEAR

	Total Payroll	23% Benefits	Expensed Payroll	23% Benefits	Total Overtime
Administrative	$ 941,463	$ 216,536	$ 798,041	$ 183,549	
Tech Services	1,509,720	347,236	881,752	202,803	18,156
West Region Adm.	366,834	84,372	264,217	60,770	
Madisonville Operations	1,441,794	331,613	997,486	229,422	29,832
Owensboro Operations	1,628,252	374,498	1,111,611	255,671	56,396
Paducah Operations	1,482,530	340,982	1,038,707	238,903	34,448
East Region Adm.	338,753	77,913	241,980	55,655	
Bowling Green Operations	2,360,270	542,878	1,654,018	380,426	62,916
Danville Operations	1,719,111	395,396	1,237,744	284,681	37,440
Totals	11,788,727	2,711,423	8,225,556	1,891,880	239,188

DATA REQUEST 206
SCHEDULE A

FORECAST YEAR PAYROLL TAXES

SUTA	Employee count x applicable rate			$ 6,768
FUTA	Employee count x applicable rate			15,791
FICA	Total payroll	11,788,727		
	Less officers payroll	806,848		
	x 7.65%	10,981,879	840,114	
	Plus Officers computed FICA		47,709	
	Total FICA			887,823
	TOTAL PAYROLL TAXES			$ 910,382

DATA REQUEST 206
SCHEDULE B

FORECAST YEAR

	President	VP Fin & Controller	VP Marketing	VP Rates & Regulatory	VP Tech Services	VP Human Resources	VP East Region	VP West Region	TOTAL
Base Earnings	135,219.00	98,576.00	90,822.00	99,787.00	103,023.00	94,200.00	91,148.00	94,073.00	806,848.00
Imputed Life	718.44	1,224.76	498.48	629.91	559.53	672.10	533.88	235.07	5,072.18
Performance Plan	13,090.00	9,573.00	8,739.00	9,394.00	9,906.00	9,059.00	8,908.00	9,193.00	77,862.00
Car Allowance	-	-	-	-	-	-	-	-	-
Res Stk Plan	12,000.00	-	-	-	-	-	-	-	12,000.00
Res Stk Dividends	-	-	-	-	-	-	-	-	-
Relocation	-	-	-	-	-	-	-	-	-
Mini Med	4,000.00	-	-	-	-	-	-	-	4,000.00
Total Other	29,808.44	10,797.76	9,237.48	10,023.91	10,465.53	9,731.10	9,441.88	9,428.07	98,934.18
Total Wages	165,027.44	109,373.76	100,059.48	109,810.91	113,488.53	103,931.10	100,589.88	103,501.07	905,782.18
									905,782.18
Pension	(10,229.00)	(7,457.00)	(6,870.00)	(7,549.00)	(7,793.00)	(7,126.00)	(6,895.00)	(7,116.00)	(61,035.00)
FAS 106	17,184.00	12,527.00	11,542.00	12,681.00	13,093.00	11,971.00	11,583.00	11,955.00	102,536.00
Total Pension	6,955.00	5,070.00	4,672.00	5,132.00	5,300.00	4,845.00	4,688.00	4,839.00	41,501.00
Worker Comp.	1,799.00	1,312.00	1,208.00	1,328.00	1,371.00	1,253.00	1,213.00	1,252.00	10,736.00
Basic Life	829.00	605.00	557.00	612.00	632.00	578.00	559.00	577.00	4,949.00
Package Ins.	15,849.00	11,554.00	10,645.00	11,696.00	12,075.00	11,041.00	10,683.00	11,026.00	94,569.00
LTD	704.00	513.00	473.00	520.00	537.00	491.00	475.00	490.00	4,203.00

DATA REQUEST 206
SCHEDULE B

Mini-Med	-	-	-	-	-	-	-	-	-
ESOP Match	4,518.00	3,294.00	3,035.00	3,334.00	3,442.00	3,148.00	3,046.00	3,143.00	26,960.00
ESOP Other	264.00	193.00	178.00	195.00	201.00	184.00	178.00	184.00	1,577.00
Total Other Benefits	23,963.00	17,471.00	16,096.00	17,685.00	18,258.00	16,695.00	16,154.00	16,672.00	142,994.00
Total Employee Benefits	30,918.00	22,541.00	20,768.00	22,817.00	23,558.00	21,540.00	20,842.00	21,511.00	184,495.00
									184,495.00
F.I.C.A.	6,461.88	5,930.55	5,818.12	5,948.11	5,995.03	5,867.10	5,822.85	5,865.26	47,708.90
Federal Unemployement	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	448.00
State Unemployment	12.56	12.56	12.56	12.56	12.56	12.56	12.56	12.56	100.48
Total Payroll Taxes	6,530.44	5,999.11	5,886.68	6,016.67	6,063.59	5,935.66	5,891.41	5,933.82	48,257.38
Total	202,475.88	137,913.87	126,714.16	138,644.58	143,110.13	131,406.76	127,323.29	130,945.89	1,138,534.55

WEXS- Labor Recap

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WEXS

Last Consolidated: 4/1/99 8:41 AM

LABOR RECAP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	62,834	66,078	69,452	63,764	63,764	69,666	60,814	69,831	67,266	64,314	70,354	64,452	792,589
EMPLOYEE BENEFITS	14,452	15,199	15,974	14,666	14,666	16,023	13,986	16,061	15,471	14,793	16,182	14,825	182,298
TOTAL EXPENSE LABOR	77,286	81,277	85,426	78,430	78,430	85,689	74,800	85,892	82,737	79,107	86,536	79,277	974,887
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	7,470	7,854	8,313	7,695	7,695	8,405	7,339	8,405	8,050	7,695	8,464	7,754	95,189
EMPLOYEE BENEFITS	1,718	1,806	1,911	1,769	1,769	1,933	1,689	1,933	1,851	1,769	1,946	1,783	21,877
TOTAL BU A&G OVERHEAD LABOR	9,188	9,660	10,224	9,464	9,464	10,338	9,028	10,338	9,901	9,464	10,410	9,537	117,016
B/S OTHER RECAP													
LABOR	3,699	3,876	4,052	3,847	3,847	4,200	3,671	4,200	4,024	3,847	4,200	3,847	47,310
EMPLOYEE BENEFITS	851	891	932	885	885	966	844	966	926	885	966	885	10,882
TOTAL B/S OTHER LABOR	4,550	4,767	4,984	4,732	4,732	5,166	4,515	5,166	4,950	4,732	5,166	4,732	58,192
TOTAL LABOR													
LABOR	74,003	77,808	81,817	75,306	75,306	82,271	71,824	82,436	79,340	75,856	83,018	76,053	985,038
EMPLOYEE BENEFITS	17,021	17,896	18,817	17,320	17,320	18,922	16,519	18,960	18,248	17,447	19,094	17,493	215,057
TOTAL	91,024	95,704	100,634	92,626	92,626	101,193	88,343	101,396	97,588	93,303	102,112	93,546	1,150,095

Schedule 1A

WTSR

Last Consolidated: [illegible]

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	69,819	73,295	76,517	70,866	70,866	77,419	67,762	77,621	74,767	71,665	78,313	71,957	880,867
EMPLOYEE BENEFITS	16,058	16,857	17,599	16,300	16,300	17,806	15,585	17,852	17,197	16,483	18,011	16,550	202,598
TOTAL EXPENSE LABOR	85,877	90,152	94,116	87,166	87,166	95,225	83,347	95,473	91,964	88,148	96,324	88,507	1,083,465
CAPITAL DIRECT RECAP													
LABOR	5,807	6,092	6,371	5,868	5,868	6,429	5,682	6,522	6,280	6,013	6,581	6,039	73,552
EMPLOYEE BENEFITS	1,336	1,401	1,465	1,350	1,350	1,479	1,307	1,500	1,444	1,383	1,514	1,389	16,918
TOTAL CAPITAL DIRECT LABOR	7,143	7,493	7,836	7,218	7,218	7,908	6,989	8,022	7,724	7,396	8,095	7,428	90,470
BU A&G OVERHEAD RECAP													
LABOR	43,537	45,795	47,846	44,223	44,223	48,322	42,269	48,766	46,836	44,789	48,887	44,789	550,282
EMPLOYEE BENEFITS	10,014	10,533	11,005	10,171	10,171	11,114	9,722	11,216	10,772	10,301	11,244	10,301	126,564
TOTAL BU A&G OVERHEAD LABOR	53,551	56,328	58,851	54,394	54,394	59,436	51,991	59,982	57,608	55,090	60,131	55,090	676,846
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	119,163	125,182	130,734	120,957	120,957	132,170	115,713	132,909	127,883	122,467	133,781	122,785	1,504,701
EMPLOYEE BENEFITS	27,408	28,791	30,069	27,821	27,821	30,399	26,614	30,568	29,413	28,167	30,769	28,240	346,080
TOTAL	146,571	153,973	160,803	148,778	148,778	162,569	142,327	163,477	157,296	150,634	164,550	151,025	1,850,781

Schedule 1A

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LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	14,488	15,167	15,847	14,488	14,673	16,031	13,993	16,190	15,511	14,832	16,190	14,832	182,242
EMPLOYEE BENEFITS	3,332	3,488	3,645	3,332	3,375	3,687	3,218	3,724	3,568	3,411	3,724	3,411	41,915
TOTAL EXPENSE LABOR	17,820	18,655	19,492	17,820	18,048	19,718	17,211	19,914	19,079	18,243	19,914	18,243	224,157
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	4,829	5,056	5,281	4,829	4,890	5,343	4,665	5,396	5,170	4,943	5,396	4,943	60,741
EMPLOYEE BENEFITS	1,111	1,163	1,215	1,111	1,125	1,229	1,073	1,241	1,189	1,137	1,241	1,137	13,972
TOTAL BU A&G OVERHEAD LAE	5,940	6,219	6,496	5,940	6,015	6,572	5,738	6,637	6,359	6,080	6,637	6,080	74,713
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	19,317	20,223	21,128	19,317	19,563	21,374	18,658	21,586	20,681	19,775	21,586	19,775	242,983
EMPLOYEE BENEFITS	4,443	4,651	4,860	4,443	4,500	4,916	4,291	4,965	4,757	4,548	4,965	4,548	55,887
TOTAL	23,760	24,874	25,988	23,760	24,063	26,290	22,949	26,551	25,438	24,323	26,551	24,323	298,870

Schedule 1A

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	6,419	6,724	7,030	6,485	6,485	7,286	6,370	7,286	6,980	6,676	7,286	6,676	81,703
EMPLOYEE BENEFITS	1,476	1,547	1,617	1,492	1,492	1,676	1,465	1,676	1,605	1,535	1,676	1,535	18,792
TOTAL EXPENSE LABOR	7,895	8,271	8,647	7,977	7,977	8,962	7,835	8,962	8,585	8,211	8,962	8,211	100,495
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	3,277	3,433	3,588	3,304	3,304	3,719	3,251	3,719	3,564	3,407	3,719	3,407	41,692
EMPLOYEE BENEFITS	754	790	825	760	760	855	748	855	820	784	855	784	9,590
TOTAL BU A&G OVERHEAD LAE	4,031	4,223	4,413	4,064	4,064	4,574	3,999	4,574	4,384	4,191	4,574	4,191	51,282
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	9,696	10,157	10,618	9,789	9,789	11,005	9,621	11,005	10,544	10,083	11,005	10,083	123,395
EMPLOYEE BENEFITS	2,230	2,337	2,442	2,252	2,252	2,531	2,213	2,531	2,425	2,319	2,531	2,319	28,382
TOTAL	11,926	12,494	13,060	12,041	12,041	13,536	11,834	13,536	12,969	12,402	13,536	12,402	151,777

WMVO- Labor Recap

Schedule 1 A

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WMVO

Last Consolidated: [illegible] [illegible] AM

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	79,395	81,030	85,549	80,025	80,149	87,224	77,022	87,521	84,123	80,744	87,770	80,782	991,334
EMPLOYEE BENEFITS	18,261	18,637	19,676	18,406	18,434	20,061	17,715	20,130	19,348	18,571	20,187	18,579	228,005
TOTAL EXPENSE LABOR	97,656	99,667	105,225	98,431	98,583	107,285	94,737	107,651	103,471	99,315	107,957	99,361	1,219,339
CAPITAL DIRECT RECAP													
LABOR	16,720	17,196	18,184	16,814	16,864	18,425	16,159	18,557	17,774	16,993	18,629	17,064	209,379
EMPLOYEE BENEFITS	3,845	3,956	4,182	3,868	3,879	4,238	3,717	4,268	4,088	3,909	4,285	3,925	48,160
TOTAL CAPITAL DIRECT LABOR	20,565	21,152	22,366	20,682	20,743	22,663	19,876	22,825	21,862	20,902	22,914	20,989	257,539
BU A&G OVERHEAD RECAP													
LABOR	11,672	12,064	12,696	11,854	11,854	12,958	11,310	12,967	12,414	11,927	13,164	12,060	146,940
EMPLOYEE BENEFITS	2,685	2,775	2,920	2,726	2,726	2,981	2,601	2,983	2,855	2,743	3,029	2,774	33,798
TOTAL BU A&G OVERHEAD LABOR	14,357	14,839	15,616	14,580	14,580	15,939	13,911	15,950	15,269	14,670	16,193	14,834	180,738
B/S OTHER RECAP													
LABOR	6,753	6,988	7,368	6,762	6,878	7,514	6,581	7,553	7,234	6,917	7,577	6,941	85,066
EMPLOYEE BENEFITS	1,553	1,607	1,695	1,555	1,582	1,729	1,514	1,738	1,663	1,591	1,743	1,597	19,567
TOTAL B/S OTHER LABOR	8,306	8,595	9,063	8,317	8,460	9,243	8,095	9,291	8,897	8,508	9,320	8,538	104,633
TOTAL LABOR													
LABOR	114,540	117,278	123,797	115,455	115,745	126,121	111,072	126,598	121,545	116,581	127,140	116,847	1,432,719
EMPLOYEE BENEFITS	26,344	26,975	28,473	26,555	26,621	29,009	25,547	29,119	27,954	26,814	29,244	26,875	329,530
TOTAL	140,884	144,253	152,270	142,010	142,366	155,130	136,619	155,717	149,499	143,395	156,384	143,722	1,762,249

WOOP- Labor Recap

Schedule 1A

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WOOP

Last Consolidated: 7/1/99 8:41 AM

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	86,883	92,760	96,760	89,960	89,960	96,289	84,964	96,612	93,033	89,435	97,178	89,884	1,108,718
EMPLOYEE BENEFITS	19,983	21,335	22,255	20,691	20,691	22,146	19,542	22,220	21,398	20,570	22,350	20,673	258,854
TOTAL EXPENSE LABOR	106,866	114,095	119,015	110,651	110,651	118,435	104,506	118,832	114,431	110,005	119,528	110,557	1,357,572
CAPITAL DIRECT RECAP													
LABOR	24,594	25,883	27,066	25,227	25,227	27,652	24,172	27,708	26,578	25,421	27,749	25,477	312,754
EMPLOYEE BENEFITS	5,657	5,953	6,225	5,802	5,802	6,360	5,560	6,373	6,113	5,847	6,382	5,860	71,934
TOTAL CAPITAL DIRECT LABOR	30,251	31,836	33,291	31,029	31,029	34,012	29,732	34,081	32,691	31,268	34,131	31,337	384,688
BU A&G OVERHEAD RECAP													
LABOR	10,671	11,178	11,687	10,826	10,826	12,032	10,510	12,032	11,525	11,088	12,104	11,088	135,567
EMPLOYEE BENEFITS	2,454	2,571	2,688	2,490	2,490	2,767	2,417	2,767	2,651	2,550	2,784	2,550	31,179
TOTAL BU A&G OVERHEAD LABOR	13,125	13,749	14,375	13,316	13,316	14,799	12,927	14,799	14,176	13,638	14,888	13,638	166,746
B/S OTHER RECAP													
LABOR	5,061	5,317	5,564	5,211	5,211	5,700	4,983	5,710	5,476	5,241	5,721	5,252	64,447
EMPLOYEE BENEFITS	1,164	1,223	1,280	1,198	1,198	1,311	1,146	1,313	1,259	1,205	1,315	1,208	14,820
TOTAL B/S OTHER LABOR	6,225	6,540	6,844	6,409	6,409	7,011	6,129	7,023	6,735	6,446	7,036	6,460	79,267
TOTAL LABOR													
LABOR	127,209	135,188	141,077	131,224	131,224	141,673	124,629	142,062	136,612	131,185	142,752	131,701	1,616,486
EMPLOYEE BENEFITS	29,258	31,082	32,448	30,181	30,181	32,584	28,665	32,673	31,421	30,172	32,831	30,291	371,787
TOTAL	156,467	166,220	173,525	161,405	161,405	174,257	153,294	174,735	168,033	161,357	175,583	161,992	1,988,273

WPDO- Labor Recap

Schedule 1A

WPDO

Last Consolidated: 7/1/99 8:41 AM

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	87,914	84,730	91,132	82,902	82,099	88,566	78,961	88,543	86,198	85,190	91,957	84,288	1,032,480
EMPLOYEE BENEFITS	20,221	19,487	20,961	19,068	18,883	20,371	18,161	20,365	19,826	19,593	21,151	19,386	237,478
TOTAL EXPENSE LABOR	108,135	104,217	112,093	101,970	100,982	108,937	97,122	108,908	106,024	104,783	113,108	103,674	1,269,953
CAPITAL DIRECT RECAP													
LABOR	18,711	19,669	20,650	19,034	18,974	20,669	18,144	20,689	20,093	19,310	21,162	19,465	236,570
EMPLOYEE BENEFITS	4,303	4,524	4,749	4,377	4,364	4,754	4,173	4,759	4,622	4,441	4,868	4,476	54,410
TOTAL CAPITAL DIRECT LABOR	23,014	24,193	25,399	23,411	23,338	25,423	22,317	25,448	24,715	23,751	26,030	23,941	290,980
BU A&G OVERHEAD RECAP													
LABOR	11,826	12,390	12,952	11,892	11,892	13,017	11,330	13,017	12,729	12,293	13,419	12,293	149,050
EMPLOYEE BENEFITS	2,720	2,850	2,979	2,735	2,735	2,994	2,606	2,994	2,928	2,827	3,086	2,827	34,281
TOTAL BU A&G OVERHEAD LABOR	14,546	15,240	15,931	14,627	14,627	16,011	13,936	16,011	15,657	15,120	16,505	15,120	183,331
B/S OTHER RECAP													
LABOR	4,379	4,597	4,805	4,422	4,422	4,838	4,213	4,838	4,749	4,541	4,969	4,554	55,327
EMPLOYEE BENEFITS	1,007	1,057	1,105	1,017	1,017	1,113	970	1,113	1,093	1,045	1,143	1,048	12,728
TOTAL B/S OTHER LABOR	5,386	5,654	5,910	5,439	5,439	5,951	5,183	5,951	5,842	5,586	6,112	5,602	68,055
TOTAL LABOR													
LABOR	122,880	121,386	129,539	118,250	117,887	127,090	112,648	127,087	123,769	121,834	131,507	120,600	1,473,427
EMPLOYEE BENEFITS	28,251	27,918	29,794	27,197	26,999	29,232	25,910	29,231	28,469	27,906	30,248	27,737	338,892
TOTAL	151,081	149,304	159,333	145,447	144,386	156,322	138,558	156,318	152,238	149,240	161,755	148,337	1,812,319

Schedule 1A

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	12,873	13,479	14,084	12,999	12,999	14,341	12,523	14,341	13,736	13,232	14,443	13,232	162,282
EMPLOYEE BENEFITS	2,961	3,100	3,239	2,990	2,990	3,298	2,880	3,298	3,159	3,043	3,322	3,043	37,328
TOTAL EXPENSE LABOR	15,834	16,579	17,323	15,989	15,989	17,639	15,403	17,639	16,895	16,275	17,765	16,275	199,605
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	4,291	4,492	4,695	4,333	4,333	4,781	4,178	4,781	4,578	4,411	4,815	4,411	54,097
EMPLOYEE BENEFITS	987	1,033	1,080	997	997	1,100	960	1,100	1,053	1,015	1,107	1,015	12,444
TOTAL BU A&G OVERHEAD LAE	5,278	5,525	5,775	5,330	5,330	5,881	5,138	5,881	5,631	5,426	5,922	5,426	66,541
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	17,164	17,971	18,779	17,332	17,332	19,122	16,699	19,122	18,314	17,643	19,258	17,643	216,379
EMPLOYEE BENEFITS	3,948	4,133	4,319	3,987	3,987	4,398	3,840	4,398	4,212	4,058	4,429	4,058	49,767
TOTAL	21,112	22,104	23,098	21,319	21,319	23,520	20,539	23,520	22,526	21,701	23,687	21,701	266,146

LABOR RECAP

Schedule 1A

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	6,115	6,406	6,697	6,115	6,115	6,883	6,009	6,883	6,591	6,359	6,942	6,359	77,474
EMPLOYEE BENEFITS	1,406	1,473	1,540	1,406	1,406	1,583	1,382	1,583	1,516	1,463	1,597	1,463	17,618
TOTAL EXPENSE LABOR	7,521	7,879	8,237	7,521	7,521	8,466	7,391	8,466	8,107	7,822	8,539	7,822	95,292
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	3,293	3,450	3,607	3,293	3,293	3,706	3,236	3,706	3,550	3,425	3,738	3,425	41,722
EMPLOYEE BENEFITS	757	794	830	757	757	852	744	852	817	788	860	788	9,596
TOTAL BU A&G OVERHEAD LAE	4,050	4,244	4,437	4,050	4,050	4,558	3,980	4,558	4,367	4,213	4,598	4,213	51,318
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	9,408	9,856	10,304	9,408	9,408	10,589	9,245	10,589	10,141	9,784	10,680	9,784	119,196
EMPLOYEE BENEFITS	2,163	2,267	2,370	2,163	2,163	2,435	2,126	2,435	2,333	2,251	2,457	2,251	27,414
TOTAL	11,571	12,123	12,674	11,571	11,571	13,024	11,371	13,024	12,474	12,035	13,137	12,035	146,610

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LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	130,380	136,109	142,611	132,454	132,563	144,153	127,321	144,720	139,387	133,873	145,539	134,728	1,643,838
EMPLOYEE BENEFITS	29,988	31,305	32,801	30,465	30,490	33,155	29,285	33,286	32,059	30,791	33,475	30,987	378,087
TOTAL EXPENSE LABOR	160,368	167,414	175,412	162,919	163,053	177,308	156,606	178,006	171,446	164,664	179,014	165,715	2,021,925
CAPITAL DIRECT RECAP													
LABOR	28,057	29,373	30,709	28,453	28,463	31,195	27,364	31,364	30,065	28,751	31,404	28,930	354,128
EMPLOYEE BENEFITS	6,453	6,756	7,062	6,544	6,546	7,176	6,294	7,214	6,916	6,612	7,223	6,654	81,450
TOTAL CAPITAL DIRECT LABOR	34,510	36,129	37,771	34,997	35,009	38,371	33,658	38,578	36,981	35,363	38,627	35,584	435,578
BU A&G OVERHEAD RECAP													
LABOR	16,187	16,955	17,719	16,262	16,262	17,870	15,578	17,888	17,324	16,674	18,217	16,748	203,684
EMPLOYEE BENEFITS	3,723	3,901	4,076	3,741	3,741	4,110	3,583	4,114	3,985	3,836	4,190	3,853	46,853
TOTAL BU A&G OVERHEAD LABOR	19,910	20,856	21,795	20,003	20,003	21,980	19,161	22,002	21,309	20,510	22,407	20,601	250,537
B/S OTHER RECAP													
LABOR	11,368	11,892	12,430	11,513	11,515	12,682	11,139	12,737	12,215	11,692	12,746	11,746	143,675
EMPLOYEE BENEFITS	2,614	2,735	2,860	2,648	2,648	2,917	2,562	2,930	2,810	2,689	2,931	2,702	33,046
TOTAL B/S OTHER LABOR	13,982	14,627	15,290	14,161	14,163	15,599	13,701	15,667	15,025	14,381	15,677	14,448	176,721
TOTAL LABOR													
LABOR	185,992	194,329	203,469	188,682	188,803	205,900	181,402	206,709	198,991	190,990	207,906	192,152	2,345,325
EMPLOYEE BENEFITS	42,778	44,697	46,799	43,398	43,425	47,358	41,724	47,544	45,770	43,928	47,819	44,196	539,436
TOTAL	228,770	239,026	250,268	232,080	232,228	253,258	223,126	254,253	244,761	234,918	255,725	236,348	2,884,761

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Schedule 1A

LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	97,688	102,165	106,688	98,974	99,059	108,003	95,059	108,194	104,195	100,394	109,221	100,809	1,230,449
EMPLOYEE BENEFITS	22,469	23,498	24,538	22,764	22,784	24,840	21,864	24,884	23,965	23,091	25,120	23,186	283,003
TOTAL EXPENSE LABOR	120,157	125,663	131,226	121,738	121,843	132,843	116,923	133,078	128,160	123,485	134,341	123,995	1,513,452
CAPITAL DIRECT RECAP													
LABOR	20,147	21,148	22,125	20,301	20,389	22,366	19,558	22,415	21,521	20,675	22,609	20,756	254,010
EMPLOYEE BENEFITS	4,634	4,864	5,089	4,669	4,689	5,144	4,499	5,155	4,950	4,755	5,200	4,774	58,422
TOTAL CAPITAL DIRECT LABOR	24,781	26,012	27,214	24,970	25,078	27,510	24,057	27,570	26,471	25,430	27,809	25,530	312,432
BU A&G OVERHEAD RECAP													
LABOR	12,935	13,551	14,167	13,164	13,164	14,451	12,603	14,460	13,925	13,451	14,682	13,451	164,004
EMPLOYEE BENEFITS	2,975	3,117	3,258	3,028	3,028	3,324	2,899	3,326	3,203	3,093	3,377	3,093	37,721
TOTAL BU A&G OVERHEAD LABOR	15,910	16,668	17,425	16,192	16,192	17,775	15,502	17,786	17,128	16,544	18,059	16,544	201,725
B/S OTHER RECAP													
LABOR	4,740	4,976	5,200	4,857	4,870	5,330	4,656	5,339	5,121	4,904	5,360	4,910	60,263
EMPLOYEE BENEFITS	1,090	1,145	1,196	1,118	1,120	1,226	1,072	1,228	1,178	1,128	1,233	1,130	13,864
TOTAL B/S OTHER LABOR	5,830	6,121	6,396	5,975	5,990	6,556	5,728	6,567	6,299	6,032	6,593	6,040	74,127
TOTAL LABOR													
LABOR	135,510	141,840	148,180	137,296	137,482	150,150	131,876	150,408	144,762	139,424	151,872	139,926	1,708,726
EMPLOYEE BENEFITS	31,168	32,624	34,081	31,579	31,621	34,534	30,334	34,593	33,296	32,067	34,930	32,183	393,010
TOTAL	166,678	174,464	182,261	168,875	169,103	184,684	162,210	185,001	178,058	171,491	186,802	172,109	2,101,736

WKCC- Labor Recap

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LABOR RECAP

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EXPENSE RECAP													
LABOR	654,808	677,943	712,367	659,032	658,732	715,861	630,798	717,742	691,787	666,714	725,193	667,999	8,178,976
EMPLOYEE BENEFITS	150,607	155,926	163,845	151,580	151,511	164,646	145,083	165,079	159,112	153,344	166,795	153,638	1,881,166
TOTAL EXPENSE LABOR	805,415	833,869	876,212	810,612	810,243	880,507	775,881	882,821	850,899	820,058	891,988	821,637	10,060,142
CAPITAL DIRECT RECAP													
LABOR	114,036	119,361	125,105	115,697	115,785	126,736	111,079	127,255	122,311	117,163	128,134	117,731	1,440,393
EMPLOYEE BENEFITS	26,228	27,454	28,772	26,610	26,630	29,151	25,550	29,269	28,133	26,947	29,472	27,078	331,294
TOTAL CAPITAL DIRECT LABOR	140,264	146,815	153,877	142,307	142,415	155,887	136,629	156,524	150,444	144,110	157,606	144,809	1,771,687
BU A&G OVERHEAD RECAP													
LABOR	129,988	136,218	142,551	131,675	131,736	144,604	126,267	145,137	139,665	134,103	146,605	134,369	1,642,918
EMPLOYEE BENEFITS	29,898	31,333	32,787	30,285	30,299	33,259	29,042	33,381	32,124	30,843	33,719	30,905	377,875
TOTAL BU A&G OVERHEAD LABOR	159,886	167,551	175,338	161,960	162,035	177,863	155,309	178,518	171,789	164,946	180,324	165,274	2,020,793
B/S OTHER RECAP													
LABOR	36,000	37,646	39,419	36,612	36,743	40,264	35,243	40,377	38,819	37,142	40,573	37,250	456,088
EMPLOYEE BENEFITS	8,279	8,658	9,068	8,421	8,450	9,262	8,108	9,288	8,929	8,543	9,331	8,570	104,907
TOTAL B/S OTHER LABOR	44,279	46,304	48,487	45,033	45,193	49,526	43,351	49,665	47,748	45,685	49,904	45,820	560,995
TOTAL LABOR													
LABOR	934,832	971,168	1,019,442	943,016	942,996	1,027,465	903,387	1,030,511	992,582	955,122	1,040,505	957,349	11,718,375
EMPLOYEE BENEFITS	215,012	223,371	234,472	216,896	216,890	236,318	207,783	237,017	228,298	219,677	239,817	220,191	2,695,242
TOTAL	1,149,844	1,194,539	1,253,914	1,159,912	1,159,886	1,263,783	1,111,170	1,267,528	1,220,880	1,174,799	1,279,822	1,177,540	14,413,617

Sample
Schedule 1B

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		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
PAYROLL INCREASE RATE	4.00%													
BENEFITS RATE	23.00%													
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
OVERTIME LABOR														
MONTHLY AMOUNT		3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	37,296
TOTAL PAYROLL		3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	37,296
CAPITAL DIRECT	5%	155	155	155	155	155	155	155	155	155	155	155	155	1,860
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	155	155	155	155	155	155	155	155	155	155	155	155	1,860
EXPENSE PAYROLL		2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	33,576
STANDBY TIME														
MONTHLY AMOUNT		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
TOTAL PAYROLL		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
EMPLOYEE A														
BASE PAY PER HOUR	26.43	4,440	4,652	4,863	4,440	4,440	4,863	4,229	4,863	4,652	4,440	4,863	4,440	55,186
MONTH OF INCREASE	10	0	0	0	0	0	0	0	0	0	178	178	178	534
TOTAL PAYROLL		4,440	4,652	4,863	4,440	4,440	4,863	4,229	4,863	4,652	4,618	5,041	4,618	55,720
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	35%	1,554	1,628	1,702	1,554	1,554	1,702	1,480	1,702	1,628	1,616	1,764	1,616	19,500
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,886	3,024	3,161	2,886	2,886	3,161	2,749	3,161	3,024	3,002	3,277	3,002	36,220
EMPLOYEE B														
BASE PAY PER HOUR	14.99	2,518	2,638	2,758	2,518	2,518	2,758	2,398	2,758	2,638	2,518	2,758	2,518	31,299
MONTH OF INCREASE	7	0	0	0	0	0	0	101	101	101	101	101	101	606
TOTAL PAYROLL		2,518	2,638	2,758	2,518	2,518	2,758	2,499	2,859	2,739	2,619	2,859	2,619	31,905
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	252	264	276	252	252	276	250	286	274	262	286	262	3,192
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,266	2,374	2,482	2,266	2,266	2,482	2,249	2,573	2,465	2,357	2,573	2,357	28,713

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		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
EMPLOYEE C														
BASE PAY PER HOUR	12.08	2,029	2,126	2,223	2,029	2,029	2,223	1,933	2,223	2,126	2,029	2,223	2,029	25,223
MONTH OF INCREASE	8	0	0	0	0	0	0	0	81	81	81	81	81	405
TOTAL PAYROLL		2,029	2,126	2,223	2,029	2,029	2,223	1,933	2,304	2,207	2,110	2,304	2,110	25,628
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	203	213	222	203	203	222	193	230	221	211	230	211	2,562
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,826	1,913	2,001	1,826	1,826	2,001	1,740	2,074	1,986	1,899	2,074	1,899	23,066
EMPLOYEE D														
BASE PAY PER HOUR	11.08	1,861	1,950	2,039	1,861	1,861	2,039	1,773	2,039	1,950	1,861	2,039	1,861	23,135
MONTH OF INCREASE	1	74	74	74	74	74	74	74	74	74	74	74	74	888
TOTAL PAYROLL		1,935	2,024	2,113	1,935	1,935	2,113	1,847	2,113	2,024	1,935	2,113	1,935	24,023
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	194	202	211	194	194	211	185	211	202	194	211	194	2,403
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,741	1,822	1,902	1,741	1,741	1,902	1,662	1,902	1,822	1,741	1,902	1,741	21,620
EMPLOYEE E														
BASE PAY PER HOUR	20.76	3,488	3,654	3,820	3,488	3,488	3,820	3,322	3,820	3,654	3,488	3,820	3,488	43,347
MONTH OF INCREASE	11	0	0	0	0	0	0	0	0	0	0	140	140	280
TOTAL PAYROLL		3,488	3,654	3,820	3,488	3,488	3,820	3,322	3,820	3,654	3,488	3,960	3,628	43,627
CAPITAL DIRECT	15%	523	548	573	523	523	573	498	573	548	523	594	544	6,543
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,965	3,106	3,247	2,965	2,965	3,247	2,824	3,247	3,106	2,965	3,366	3,084	37,084
EMPLOYEE F														
BASE PAY PER HOUR	19.03	3,197	3,349	3,502	3,197	3,197	3,502	3,045	3,502	3,349	3,197	3,502	3,197	39,735
MONTH OF INCREASE	4	0	0	0	128	128	128	128	128	128	128	128	128	1,152
TOTAL PAYROLL		3,197	3,349	3,502	3,325	3,325	3,630	3,173	3,630	3,477	3,325	3,630	3,325	40,887
CAPITAL DIRECT	10%	320	335	350	333	333	363	317	363	348	333	363	333	4,091
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,877	3,014	3,152	2,992	2,992	3,267	2,856	3,267	3,129	2,992	3,267	2,992	36,796

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		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
EMPLOYEE G														
BASE PAY PER HOUR	15.37	2,582	2,705	2,828	2,582	2,582	2,828	2,459	2,828	2,705	2,582	2,828	2,582	32,093
MONTH OF INCREASE	4	0	0	0	103	103	103	103	103	103	103	103	103	927
TOTAL PAYROLL		2,582	2,705	2,828	2,685	2,685	2,931	2,562	2,931	2,808	2,685	2,931	2,685	33,020
CAPITAL DIRECT	65%	1,678	1,758	1,838	1,745	1,745	1,905	1,665	1,905	1,825	1,745	1,905	1,745	21,459
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	516	541	566	537	537	586	512	586	562	537	586	537	6,603
EXPENSE PAYROLL		388	406	424	403	403	440	385	440	421	403	440	403	4,958
EMPLOYEE H														
BASE PAY PER HOUR	17.66	2,967	3,108	3,249	2,967	2,967	3,249	2,826	3,249	3,108	2,967	3,249	2,967	36,874
MONTH OF INCREASE	4	0	0	0	119	119	119	119	119	119	119	119	119	1,071
TOTAL PAYROLL		2,967	3,108	3,249	3,086	3,086	3,368	2,945	3,368	3,227	3,086	3,368	3,086	37,945
CAPITAL DIRECT	5%	148	155	162	154	154	168	147	168	161	154	168	154	1,893
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	148	155	162	154	154	168	147	168	161	154	168	154	1,893
EXPENSE PAYROLL		2,671	2,798	2,925	2,778	2,778	3,032	2,651	3,032	2,905	2,778	3,032	2,778	34,159
EMPLOYEE I														
BASE PAY PER HOUR	17.43	2,927	3,066	3,205	2,927	2,927	3,205	2,787	3,205	3,066	2,927	3,205	2,927	36,373
MONTH OF INCREASE	1	117	117	117	117	117	117	117	117	117	117	117	117	1,404
TOTAL PAYROLL		3,044	3,183	3,322	3,044	3,044	3,322	2,904	3,322	3,183	3,044	3,322	3,044	37,777
CAPITAL DIRECT	65%	1,978	2,069	2,159	1,978	1,978	2,159	1,888	2,159	2,069	1,978	2,159	1,978	24,552
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	609	637	664	609	609	664	581	664	637	609	664	609	7,556
EXPENSE PAYROLL		457	477	499	457	457	499	435	499	477	457	499	457	5,669
EMPLOYEE J														
BASE PAY PER HOUR	18.98	3,357	3,516	3,676	3,357	3,357	3,676	3,197	3,676	3,516	3,357	3,676	3,357	41,718
MONTH OF INCREASE	4	0	0	0	134	134	134	134	134	134	134	134	134	1,206
TOTAL PAYROLL		3,357	3,516	3,676	3,491	3,491	3,810	3,331	3,810	3,650	3,491	3,810	3,491	42,924
CAPITAL DIRECT	65%	2,182	2,286	2,390	2,269	2,269	2,477	2,165	2,477	2,373	2,269	2,477	2,269	27,903
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	671	703	735	698	698	762	666	762	730	698	762	698	8,583
EXPENSE PAYROLL		504	527	551	524	524	571	500	571	547	524	571	524	6,438

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		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
PAYROLL INCREASE RATE	4.00%													
BENEFITS RATE	23.00%													
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
EMPLOYEE K														
BASE PAY PER HOUR	15.13	2,542	2,663	2,784	2,542	2,542	2,784	2,421	2,784	2,663	2,542	2,784	2,542	31,591
MONTH OF INCREASE	1	102	102	102	102	102	102	102	102	102	102	102	102	1,224
TOTAL PAYROLL		2,644	2,765	2,886	2,644	2,644	2,886	2,523	2,886	2,765	2,644	2,886	2,644	32,815
CAPITAL DIRECT	65%	1,718	1,797	1,876	1,718	1,718	1,876	1,640	1,876	1,797	1,718	1,876	1,718	21,328
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	529	553	577	529	529	577	505	577	553	529	577	529	6,564
EXPENSE PAYROLL		397	415	433	397	397	433	378	433	415	397	433	397	4,923
EMPLOYEE L														
BASE PAY PER HOUR	17.98	3,021	3,164	3,308	3,021	3,021	3,308	2,877	3,308	3,164	3,021	3,308	3,021	37,542
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	121	121
TOTAL PAYROLL		3,021	3,164	3,308	3,021	3,021	3,308	2,877	3,308	3,164	3,021	3,308	3,142	37,663
CAPITAL DIRECT	65%	1,963	2,057	2,150	1,963	1,963	2,150	1,870	2,150	2,057	1,963	2,150	2,042	24,478
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	604	633	662	604	604	662	575	662	633	604	662	628	7,533
EXPENSE PAYROLL		454	474	496	454	454	496	432	496	474	454	496	472	5,652
EMPLOYEE M														
BASE PAY PER HOUR	14.07	2,364	2,476	2,589	2,364	2,364	2,589	2,251	2,589	2,476	2,364	2,589	2,364	29,378
MONTH OF INCREASE	4	0	0	0	95	95	95	95	95	95	95	95	95	855
TOTAL PAYROLL		2,364	2,476	2,589	2,459	2,459	2,684	2,346	2,684	2,571	2,459	2,684	2,459	30,233
CAPITAL DIRECT	65%	1,536	1,610	1,683	1,598	1,598	1,745	1,525	1,745	1,671	1,598	1,745	1,598	19,652
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	473	495	518	492	492	537	469	537	514	492	537	492	6,048
EXPENSE PAYROLL		355	371	388	369	369	402	352	402	386	369	402	369	4,533
EMPLOYEE N														
BASE PAY PER HOUR	12.85	2,159	2,262	2,364	2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,159	26,831
MONTH OF INCREASE	6	0	0	0	0	0	86	86	86	86	86	86	86	602
TOTAL PAYROLL		2,159	2,262	2,364	2,159	2,159	2,450	2,142	2,450	2,348	2,245	2,450	2,245	27,433
CAPITAL DIRECT	45%	971	1,018	1,064	971	971	1,103	964	1,103	1,056	1,010	1,103	1,010	12,344
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	10%	216	226	236	216	216	245	214	245	235	224	245	224	2,742
EXPENSE PAYROLL		972	1,018	1,064	972	972	1,102	964	1,102	1,057	1,011	1,102	1,011	12,347

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PAYROLL INCREASE RATE	4.00%													
BENEFITS RATE	23.00%													
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EMPLOYEE O														
BASE PAY PER HOUR	18.07	3,036	3,180	3,325	3,036	3,036	3,325	2,891	3,325	3,180	3,036	3,325	3,036	37,780
MONTH OF INCREASE	5	0	0	0	0	121	121	121	121	121	121	121	121	968
TOTAL PAYROLL		3,036	3,180	3,325	3,036	3,157	3,446	3,012	3,446	3,301	3,157	3,446	3,157	38,698
CAPITAL DIRECT	8%	243	254	266	243	253	276	241	276	264	253	276	253	3,098
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	61	64	66	61	63	69	60	69	66	63	69	63	774
EXPENSE PAYROLL		2,732	2,862	2,993	2,732	2,841	3,101	2,711	3,101	2,971	2,841	3,101	2,841	34,826
EMPLOYEE P														
BASE PAY PER HOUR	17.89	3,006	3,149	3,292	3,006	3,006	3,292	2,862	3,292	3,149	3,006	3,292	3,006	37,354
MONTH OF INCREASE	4	0	0	0	120	120	120	120	120	120	120	120	120	1,080
TOTAL PAYROLL		3,006	3,149	3,292	3,126	3,126	3,412	2,982	3,412	3,269	3,126	3,412	3,126	38,434
CAPITAL DIRECT	8%	240	252	263	250	250	273	239	273	261	250	273	250	3,074
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	60	63	66	63	63	68	60	68	65	63	68	63	770
EXPENSE PAYROLL		2,706	2,834	2,963	2,813	2,813	3,071	2,683	3,071	2,943	2,813	3,071	2,813	34,590
EMPLOYEE Q														
BASE PAY PER HOUR	13.56	2,278	2,387	2,495	2,278	2,278	2,495	2,170	2,495	2,387	2,278	2,495	2,278	28,313
MONTH OF INCREASE	3	0	0	91	91	91	91	91	91	91	91	91	91	910
TOTAL PAYROLL		2,278	2,387	2,586	2,369	2,369	2,586	2,261	2,586	2,478	2,369	2,586	2,369	29,223
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,278	2,387	2,586	2,369	2,369	2,586	2,261	2,586	2,478	2,369	2,586	2,369	29,223
EMPLOYEE R														
BASE PAY PER HOUR	15.81	2,656	2,783	2,909	2,656	2,656	2,909	2,530	2,909	2,783	2,656	2,909	2,656	33,011
MONTH OF INCREASE	3	0	0	106	106	106	106	106	106	106	106	106	106	1,060
TOTAL PAYROLL		2,656	2,783	3,015	2,762	2,762	3,015	2,636	3,015	2,889	2,762	3,015	2,762	34,071
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,656	2,783	3,015	2,762	2,762	3,015	2,636	3,015	2,889	2,762	3,015	2,762	34,071

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		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
PAYROLL INCREASE RATE	4.00%													
BENEFITS RATE	23.00%													
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
EMPLOYEE S														
BASE PAY PER HOUR	15.73	2,643	2,768	2,894	2,643	2,643	2,894	2,517	2,894	2,768	2,643	2,894	2,643	32,844
MONTH OF INCREASE	1	106	106	106	106	106	106	106	106	106	106	106	106	1,272
TOTAL PAYROLL		2,749	2,874	3,000	2,749	2,749	3,000	2,623	3,000	2,874	2,749	3,000	2,749	34,116
CAPITAL DIRECT	8%	220	230	240	220	220	240	210	240	230	220	240	220	2,730
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	55	57	60	55	55	60	52	60	57	55	60	55	681
EXPENSE PAYROLL		2,474	2,587	2,700	2,474	2,474	2,700	2,361	2,700	2,587	2,474	2,700	2,474	30,705
EMPLOYEE T														
BASE PAY PER HOUR	13.31	2,236	2,343	2,449	2,236	2,236	2,449	2,130	2,449	2,343	2,236	2,449	2,236	27,791
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	89	89	89	89	356
TOTAL PAYROLL		2,236	2,343	2,449	2,236	2,236	2,449	2,130	2,449	2,432	2,325	2,538	2,325	28,147
CAPITAL DIRECT	8%	179	187	196	179	179	196	170	196	195	186	203	186	2,252
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	45	47	49	45	45	49	43	49	49	47	51	47	566
EXPENSE PAYROLL		2,012	2,109	2,204	2,012	2,012	2,204	1,917	2,204	2,188	2,092	2,284	2,092	25,329
EMPLOYEE U														
BASE PAY PER HOUR	15.30	2,570	2,693	2,815	2,570	2,570	2,815	2,448	2,815	2,693	2,570	2,815	2,570	31,946
MONTH OF INCREASE	3	0	0	103	103	103	103	103	103	103	103	103	103	1,030
TOTAL PAYROLL		2,570	2,693	2,918	2,673	2,673	2,918	2,551	2,918	2,796	2,673	2,918	2,673	32,976
CAPITAL DIRECT	8%	206	215	233	214	214	233	204	233	224	214	233	214	2,637
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	51	54	58	53	53	58	51	58	56	53	58	53	656
EXPENSE PAYROLL		2,313	2,424	2,627	2,406	2,406	2,627	2,296	2,627	2,516	2,406	2,627	2,406	29,683
EMPLOYEE V														
BASE PAY PER HOUR	13.08	2,197	2,302	2,407	2,197	2,197	2,407	2,093	2,407	2,302	2,197	2,407	2,197	27,311
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	88	88	88	88	352
TOTAL PAYROLL		2,197	2,302	2,407	2,197	2,197	2,407	2,093	2,407	2,390	2,285	2,495	2,285	27,663
CAPITAL DIRECT	8%	176	184	193	176	176	193	167	193	191	183	200	183	2,215
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	44	46	48	44	44	48	42	48	48	46	50	46	554
EXPENSE PAYROLL		1,977	2,072	2,166	1,977	1,977	2,166	1,884	2,166	2,151	2,056	2,245	2,056	24,894

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PAYROLL INCREASE RATE 4.00%
BENEFITS RATE 23.00%

		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
EMPLOYEE W														
BASE PAY PER HOUR	15.75	2,646	2,772	2,898	2,646	2,646	2,898	2,520	2,898	2,772	2,646	2,898	2,646	32,886
MONTH OF INCREASE	4	0	0	0	106	106	106	106	106	106	106	106	106	954
TOTAL PAYROLL		2,646	2,772	2,898	2,752	2,752	3,004	2,626	3,004	2,878	2,752	3,004	2,752	33,840
CAPITAL DIRECT	8%	212	222	232	220	220	240	210	240	230	220	240	220	2,706
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	53	55	58	55	55	60	53	60	58	55	60	55	677
EXPENSE PAYROLL		2,381	2,495	2,608	2,477	2,477	2,704	2,363	2,704	2,590	2,477	2,704	2,477	30,457
EMPLOYEE X														
BASE PAY PER HOUR	18.96	3,185	3,337	3,489	3,185	3,185	3,489	3,034	3,489	3,337	3,185	3,489	3,185	39,588
MONTH OF INCREASE	4	0	0	0	127	127	127	127	127	127	127	127	127	1,143
TOTAL PAYROLL		3,185	3,337	3,489	3,312	3,312	3,616	3,161	3,616	3,464	3,312	3,616	3,312	40,731
CAPITAL DIRECT	10%	319	334	349	331	331	362	316	362	346	331	362	331	4,074
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	159	167	174	166	166	181	158	181	173	166	181	166	2,038
EXPENSE PAYROLL		2,707	2,836	2,966	2,815	2,815	3,073	2,687	3,073	2,945	2,815	3,073	2,815	34,619
EMPLOYEE Y														
BASE PAY PER HOUR	24.82	4,170	4,368	4,567	4,170	4,170	4,567	3,971	4,567	4,368	4,170	4,567	4,170	51,824
MONTH OF INCREASE	4	0	0	0	167	167	167	167	167	167	167	167	167	1,503
TOTAL PAYROLL		4,170	4,368	4,567	4,337	4,337	4,734	4,138	4,734	4,535	4,337	4,734	4,337	53,327
CAPITAL DIRECT	15%	625	655	685	651	651	710	621	710	680	651	710	651	8,000
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	208	218	228	217	217	237	207	237	227	217	237	217	2,667
EXPENSE PAYROLL		3,337	3,495	3,654	3,469	3,469	3,787	3,310	3,787	3,628	3,469	3,787	3,469	42,660
EMPLOYEE Z														
BASE PAY PER HOUR	15.37	2,582	2,705	2,828	2,582	2,582	2,828	2,459	2,828	2,705	2,582	2,828	2,582	32,093
MONTH OF INCREASE	7	0	0	0	0	0	0	103	103	103	103	103	103	618
TOTAL PAYROLL		2,582	2,705	2,828	2,582	2,582	2,828	2,562	2,931	2,808	2,685	2,931	2,685	32,711
CAPITAL DIRECT	8%	207	216	226	207	207	226	205	234	225	215	234	215	2,617
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	52	54	57	52	52	57	51	59	56	54	59	54	657
EXPENSE PAYROLL		2,323	2,435	2,545	2,323	2,323	2,545	2,306	2,638	2,527	2,416	2,638	2,416	29,437

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PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EMPLOYEE AA														
BASE PAY PER HOUR	15.08	2,533	2,654	2,775	2,538	2,533	2,775	2,413	2,775	2,654	2,533	2,775	2,533	31,487
MONTH OF INCREASE	3	0	0	101	101	101	101	101	101	101	101	101	101	1,010
TOTAL PAYROLL		2,533	2,654	2,876	2,634	2,634	2,876	2,514	2,876	2,755	2,634	2,876	2,634	32,497
CAPITAL DIRECT	8%	203	212	230	211	211	230	201	230	220	211	230	211	2,600
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	51	53	58	53	53	58	50	58	55	53	58	53	653
EXPENSE PAYROLL		2,279	2,389	2,588	2,370	2,370	2,588	2,263	2,588	2,480	2,370	2,588	2,370	29,244
EMPLOYEE BB														
BASE PAY PER HOUR	16.22	2,557	2,679	2,800	2,557	2,557	2,800	2,435	2,800	2,679	2,557	2,800	2,557	31,779
MONTH OF INCREASE	3	0	0	102	102	102	102	102	102	102	102	102	102	1,020
TOTAL PAYROLL		2,557	2,679	2,902	2,659	2,659	2,902	2,537	2,902	2,781	2,659	2,902	2,659	32,799
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,557	2,679	2,902	2,659	2,659	2,902	2,537	2,902	2,781	2,659	2,902	2,659	32,799
EMPLOYEE CC														
BASE PAY PER HOUR	12.85	2,159	2,262	2,364	2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,159	26,831
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	86	86
TOTAL PAYROLL		2,159	2,262	2,364	2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,245	26,917
CAPITAL DIRECT	65%	1,403	1,470	1,537	1,403	1,403	1,537	1,336	1,537	1,470	1,403	1,537	1,459	17,495
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	432	452	473	432	432	473	411	473	452	432	473	449	5,384
EXPENSE PAYROLL		324	340	354	324	324	354	309	354	340	324	354	337	4,038
EMPLOYEE DD														
BASE PAY PER HOUR	16.53	2,777	2,909	3,042	2,777	2,777	3,042	2,645	3,042	2,909	2,777	3,042	2,777	34,515
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	111	111
TOTAL PAYROLL		2,777	2,909	3,042	2,777	2,777	3,042	2,645	3,042	2,909	2,777	3,042	2,888	34,626
CAPITAL DIRECT	8%	222	233	243	222	222	243	212	243	233	222	243	231	2,769
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	56	58	61	56	56	61	53	61	58	56	61	58	695
EXPENSE PAYROLL		2,499	2,618	2,738	2,499	2,499	2,738	2,380	2,738	2,618	2,499	2,738	2,599	31,162

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PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	22	23	21	21	23	20	23	22	21	23	21	261
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	176	184	168	168	184	160	184	176	168	184	168	2,088
		OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	TOTAL
EMPLOYEE EE														
BASE PAY PER HOUR	26.91	4,521	4,736	4,951	4,521	4,521	4,951	4,306	4,951	4,736	4,521	4,951	4,521	56,188
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	181	181
TOTAL PAYROLL		4,521	4,736	4,951	4,521	4,521	4,951	4,306	4,951	4,736	4,521	4,951	4,702	56,369
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	35%	1,582	1,658	1,733	1,582	1,582	1,733	1,507	1,733	1,658	1,582	1,733	1,646	19,729
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,939	3,078	3,218	2,939	2,939	3,218	2,799	3,218	3,078	2,939	3,218	3,056	36,640
EMPLOYEE FF														
BASE PAY PER HOUR	9.38	1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,576	19,585
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	63	63
TOTAL PAYROLL		1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	19,648
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	19,648
EMPLOYEE GG														
BASE PAY PER HOUR	9.38	1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,576	19,585
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	63	63
TOTAL PAYROLL		1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	19,648
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,576	1,651	1,726	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	19,648

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	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
LABOR RECAP													
EXPENSE RECAP													
LABOR	63,762	63,762	69,835	60,727	70,015	67,376	64,312	70,588	64,450	68,460	68,778	65,976	798,041
EMPLOYEE BENEFITS	14,665	14,665	16,062	13,967	16,103	15,496	14,791	16,235	14,823	15,745	15,819	15,175	183,546
TOTAL EXPENSE LABOR	78,427	78,427	85,897	74,694	86,118	82,872	79,103	86,823	79,273	84,205	84,597	81,151	981,587
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	7,695	7,695	8,427	7,328	8,427	8,061	7,695	8,492	7,754	8,138	8,169	7,907	95,788
EMPLOYEE BENEFITS	1,769	1,769	1,939	1,686	1,939	1,854	1,769	1,954	1,783	1,872	1,879	1,819	22,032
TOTAL BU A&G OVERHEAD LABOR	9,464	9,464	10,366	9,014	10,366	9,915	9,464	10,446	9,537	10,010	10,048	9,726	117,820
B/S OTHER RECAP													
LABOR	3,847	3,847	4,214	3,664	4,214	4,031	3,847	4,214	3,847	4,031	4,031	3,847	47,634
EMPLOYEE BENEFITS	885	885	969	843	969	927	885	969	885	927	927	885	10,956
TOTAL B/S OTHER LABOR	4,732	4,732	5,183	4,507	5,183	4,958	4,732	5,183	4,732	4,958	4,958	4,732	58,590
TOTAL LABOR													
LABOR	75,304	75,304	82,476	71,719	82,656	79,468	75,854	83,294	76,051	80,629	80,978	77,730	941,463
EMPLOYEE BENEFITS	17,319	17,319	18,970	16,496	19,011	18,277	17,445	19,158	17,491	18,544	18,625	17,879	216,534
TOTAL	92,623	92,623	101,446	88,215	101,667	97,745	93,299	102,452	93,542	99,173	99,603	95,609	1,157,997

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LABOR RECAP	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	19,014	70,563	77,248	67,391	77,467	74,556	71,362	78,228	71,763	75,203	75,212	72,196	881,752
EMPLOYEE BENEFITS	16,229	16,229	17,768	15,501	17,818	17,148	16,413	17,993	16,505	17,296	17,299	16,606	202,805
TOTAL EXPENSE LABOR	86,792	86,792	95,016	82,892	95,285	91,704	87,775	96,221	88,268	92,499	92,511	88,802	1,084,557
CAPITAL DIRECT RECAP													
LABOR	5,859	5,859	6,427	5,667	6,530	6,280	6,004	6,594	6,039	6,329	6,329	6,039	73,956
EMPLOYEE BENEFITS	1,348	1,348	1,478	1,303	1,502	1,444	1,381	1,517	1,389	1,456	1,456	1,389	17,011
TOTAL CAPITAL DIRECT LABOR	7,207	7,207	7,905	6,970	8,032	7,724	7,385	8,111	7,428	7,785	7,785	7,428	90,967
BU A&G OVERHEAD RECAP													
LABOR	44,223	44,223	48,434	42,209	48,920	46,921	44,789	49,052	44,789	47,435	47,520	45,497	554,012
EMPLOYEE BENEFITS	10,172	10,172	11,140	9,708	11,251	10,791	10,302	11,282	10,302	10,910	10,930	10,464	127,424
TOTAL BU A&G OVERHEAD LABOR	54,395	54,395	59,574	51,917	60,171	57,712	55,091	60,334	55,091	58,345	58,450	55,961	681,436
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	120,645	120,645	132,109	115,267	132,917	127,757	122,155	133,874	122,591	128,967	129,061	123,732	1,509,720
EMPLOYEE BENEFITS	27,749	27,749	30,386	26,512	30,571	29,383	28,096	30,792	28,196	29,662	29,685	28,459	347,240
TOTAL	148,394	148,394	162,495	141,779	163,488	157,140	150,251	164,666	150,787	158,629	158,746	152,191	1,856,960

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LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	6,485	6,485	7,310	6,357	7,310	6,994	6,676	7,310	6,676	6,994	6,994	6,676	82,267
EMPLOYEE BENEFITS	1,492	1,492	1,681	1,462	1,681	1,609	1,535	1,681	1,535	1,609	1,609	1,535	18,921
TOTAL EXPENSE LABOR	7,977	7,977	8,991	7,819	8,991	8,603	8,211	8,991	8,211	8,603	8,603	8,211	101,188
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	3,304	3,304	3,732	3,248	3,732	3,569	3,407	3,732	3,407	3,569	3,569	3,407	41,978
EMPLOYEE BENEFITS	760	760	858	747	858	821	784	858	784	821	821	784	9,656
TOTAL BU A&G OVERHEAD LAE	4,064	4,064	4,590	3,993	4,590	4,390	4,191	4,590	4,191	4,390	4,390	4,191	51,634
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	9,789	9,789	11,042	9,603	11,042	10,563	10,083	11,042	10,083	10,563	10,563	10,083	124,245
EMPLOYEE BENEFITS	2,252	2,252	2,539	2,209	2,539	2,430	2,319	2,539	2,319	2,430	2,430	2,319	28,577
TOTAL	12,041	12,041	13,581	11,812	13,581	12,993	12,402	13,581	12,402	12,993	12,993	12,402	152,822

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LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	14,396	14,581	15,969	13,886	16,143	15,442	14,740	16,143	14,740	15,539	15,539	14,832	181,950
EMPLOYEE BENEFITS	3,311	3,354	3,673	3,194	3,713	3,552	3,390	3,713	3,390	3,574	3,574	3,411	41,849
TOTAL EXPENSE LABOR	17,707	17,935	19,642	17,080	19,856	18,994	18,130	19,856	18,130	19,113	19,113	18,243	223,799
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	4,798	4,859	5,322	4,628	5,380	5,147	4,912	5,380	4,912	5,179	5,179	4,943	60,639
EMPLOYEE BENEFITS	1,104	1,118	1,224	1,064	1,237	1,184	1,130	1,237	1,130	1,191	1,191	1,137	13,947
TOTAL BU A&G OVERHEAD LAE	5,902	5,977	6,546	5,692	6,617	6,331	6,042	6,617	6,042	6,370	6,370	6,080	74,586
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	19,194	19,440	21,291	18,514	21,523	20,589	19,652	21,523	19,652	20,718	20,718	19,775	242,589
EMPLOYEE BENEFITS	4,415	4,472	4,897	4,258	4,950	4,736	4,520	4,950	4,520	4,765	4,765	4,548	55,796
TOTAL	23,609	23,912	26,188	22,772	26,473	25,325	24,172	26,473	24,172	25,483	25,483	24,323	298,385

WMVO- Labor Recap

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LABOR RECAP	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	79,996	80,119	87,423	76,855	87,744	84,214	80,706	88,014	80,744	85,015	85,146	81,510	997,486
EMPLOYEE BENEFITS	18,399	18,428	20,107	17,677	20,181	19,369	18,562	20,243	18,571	19,554	19,584	18,747	229,422
TOTAL EXPENSE LABOR	98,395	98,547	107,530	94,532	107,925	103,583	99,268	108,257	99,315	104,569	104,730	100,257	1,226,908
CAPITAL DIRECT RECAP													
LABOR	16,810	16,858	18,462	16,127	18,605	17,794	16,987	18,683	17,058	18,048	18,055	17,287	210,774
EMPLOYEE BENEFITS	3,866	3,877	4,246	3,710	4,279	4,093	3,907	4,297	3,924	4,151	4,153	3,976	48,479
TOTAL CAPITAL DIRECT LABOR	20,676	20,735	22,708	19,837	22,884	21,887	20,894	22,980	20,982	22,199	22,208	21,263	259,253
BU A&G OVERHEAD RECAP													
LABOR	11,851	11,851	12,980	11,296	12,990	12,426	11,924	13,205	12,057	12,632	12,632	12,057	147,901
EMPLOYEE BENEFITS	2,726	2,726	2,985	2,599	2,988	2,857	2,743	3,037	2,774	2,905	2,905	2,774	34,019
TOTAL BU A&G OVERHEAD LABOR	14,577	14,577	15,965	13,895	15,978	15,283	14,667	16,242	14,831	15,537	15,537	14,831	181,920
B/S OTHER RECAP													
LABOR	6,761	6,876	7,530	6,569	7,572	7,245	6,915	7,598	6,939	7,313	7,313	7,002	85,633
EMPLOYEE BENEFITS	1,555	1,581	1,732	1,511	1,742	1,667	1,590	1,748	1,596	1,682	1,682	1,610	19,696
TOTAL B/S OTHER LABOR	8,316	8,457	9,262	8,080	9,314	8,912	8,505	9,346	8,535	8,995	8,995	8,612	105,329
TOTAL LABOR													
LABOR	115,418	115,704	126,395	110,847	126,911	121,679	116,532	127,500	116,798	123,008	123,146	117,856	1,441,794
EMPLOYEE BENEFITS	26,546	26,612	29,070	25,497	29,190	27,986	26,802	29,825	26,865	28,292	28,324	27,107	331,616
TOTAL	141,964	142,316	155,465	136,344	156,101	149,665	143,334	156,825	143,663	151,300	151,470	144,963	1,773,410

WOOP- Labor Recap

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LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	90,070	90,070	96,589	84,963	96,942	93,268	89,545	97,561	89,888	94,064	96,162	92,489	1,111,611
EMPLOYEE BENEFITS	20,716	20,716	22,216	19,542	22,297	21,452	20,595	22,439	20,674	21,635	22,118	21,272	255,672
TOTAL EXPENSE LABOR	110,786	110,786	118,805	104,505	119,239	114,720	110,140	120,000	110,562	115,699	118,280	113,761	1,367,283
CAPITAL DIRECT RECAP													
LABOR	25,259	25,259	27,771	24,166	27,834	26,655	25,453	27,880	25,477	26,792	26,926	25,761	315,233
EMPLOYEE BENEFITS	5,810	5,810	6,387	5,558	6,402	6,131	5,854	6,412	5,860	6,162	6,193	5,925	72,504
TOTAL CAPITAL DIRECT LABOR	31,069	31,069	34,158	29,724	34,236	32,786	31,307	34,292	31,337	32,954	33,119	31,686	387,737
BU A&G OVERHEAD RECAP													
LABOR	10,825	10,825	12,066	10,492	12,066	11,541	11,087	12,144	11,087	11,626	11,626	11,097	136,482
EMPLOYEE BENEFITS	2,490	2,490	2,775	2,414	2,775	2,655	2,550	2,793	2,550	2,674	2,674	2,552	31,392
TOTAL BU A&G OVERHEAD LABOR	13,315	13,315	14,841	12,906	14,841	14,196	13,637	14,937	13,637	14,300	14,300	13,649	167,874
B/S OTHER RECAP													
LABOR	5,214	5,214	5,722	4,979	5,733	5,489	5,244	5,746	5,252	5,512	5,534	5,287	64,926
EMPLOYEE BENEFITS	1,199	1,199	1,316	1,145	1,318	1,262	1,206	1,321	1,208	1,267	1,272	1,216	14,929
TOTAL B/S OTHER LABOR	6,413	6,413	7,038	6,124	7,051	6,751	6,450	7,067	6,460	6,779	6,806	6,503	79,855
TOTAL LABOR													
LABOR	131,368	131,368	142,148	124,600	142,575	136,958	131,329	143,331	131,704	137,994	140,248	134,634	1,628,252
EMPLOYEE BENEFITS	30,215	30,215	32,694	28,659	32,792	31,500	30,205	32,965	30,292	31,738	32,257	30,965	374,497
TOTAL	161,583	161,583	174,842	153,259	175,367	168,453	161,534	176,296	161,996	169,732	172,505	165,599	2,002,749

WPDO- Labor Recap

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LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	82,901	82,098	88,668	78,913	88,645	86,288	85,189	92,201	84,287	94,801	87,924	86,792	1,038,707
EMPLOYEE BENEFITS	19,067	18,883	20,394	18,150	20,388	19,847	19,593	21,206	19,386	21,805	20,222	19,961	238,902
TOTAL EXPENSE LABOR	101,968	100,981	109,062	97,063	109,033	106,135	104,782	113,407	103,673	116,606	108,146	106,753	1,277,609
CAPITAL DIRECT RECAP													
LABOR	19,035	18,975	20,697	18,128	20,717	20,118	19,311	21,227	19,466	20,370	20,451	19,625	238,120
EMPLOYEE BENEFITS	4,378	4,364	4,760	4,169	4,765	4,627	4,442	4,883	4,477	4,685	4,704	4,514	54,768
TOTAL CAPITAL DIRECT LABOR	23,413	23,339	25,457	22,297	25,482	24,745	23,753	26,110	23,943	25,055	25,155	24,139	292,888
BU A&G OVERHEAD RECAP													
LABOR	11,892	11,892	13,023	11,327	13,023	12,745	12,293	13,465	12,293	12,880	12,880	12,293	150,006
EMPLOYEE BENEFITS	2,735	2,735	2,996	2,605	2,996	2,932	2,827	3,098	2,827	2,963	2,963	2,827	34,504
TOTAL BU A&G OVERHEAD LABOR	14,627	14,627	16,019	13,932	16,019	15,677	15,120	16,563	15,120	15,843	15,843	15,120	184,510
B/S OTHER RECAP													
LABOR	4,422	4,422	4,843	4,211	4,843	4,757	4,541	4,988	4,554	4,770	4,782	4,564	55,697
EMPLOYEE BENEFITS	1,017	1,017	1,114	968	1,114	1,094	1,045	1,148	1,048	1,097	1,100	1,050	12,812
TOTAL B/S OTHER LABOR	5,439	5,439	5,957	5,179	5,957	5,851	5,586	6,136	5,602	5,867	5,882	5,614	68,509
TOTAL LABOR													
LABOR	118,250	117,387	127,231	112,579	127,228	123,908	121,334	131,881	120,600	132,821	126,037	123,274	1,482,530
EMPLOYEE BENEFITS	27,197	26,999	29,264	25,892	29,263	28,500	27,907	30,335	27,738	30,550	28,989	28,352	340,986
TOTAL	145,447	144,386	156,495	138,471	156,491	152,408	149,241	162,216	148,338	163,371	155,026	151,626	1,823,516

Schedule ZA

LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	6,175	6,175	6,964	6,056	6,964	6,662	6,360	6,964	6,360	6,727	6,727	6,421	78,555
EMPLOYEE BENEFITS	1,420	1,420	1,602	1,393	1,602	1,532	1,463	1,602	1,463	1,547	1,547	1,477	18,068
TOTAL EXPENSE LABOR	7,595	7,595	8,566	7,449	8,566	8,194	7,823	8,566	7,823	8,274	8,274	7,898	96,623
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	3,324	3,324	3,751	3,261	3,751	3,587	3,424	3,751	3,424	3,622	3,622	3,458	42,299
EMPLOYEE BENEFITS	765	765	863	750	863	825	788	863	788	833	833	795	9,731
TOTAL BU A&G OVERHEAD LAE	4,089	4,089	4,614	4,011	4,614	4,412	4,212	4,614	4,212	4,455	4,455	4,253	52,030
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	9,499	9,499	10,715	9,317	10,715	10,249	9,784	10,715	9,784	10,349	10,349	9,879	120,854
EMPLOYEE BENEFITS	2,185	2,185	2,465	2,143	2,465	2,357	2,251	2,465	2,251	2,380	2,380	2,272	27,799
TOTAL	11,684	11,684	13,180	11,460	13,180	12,606	12,035	13,180	12,035	12,729	12,729	12,151	148,653

Schedule 2A

LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	13,000	13,000	14,381	12,505	14,381	13,757	13,233	14,493	13,233	14,027	14,027	13,388	163,425
EMPLOYEE BENEFITS	2,990	2,990	3,308	2,876	3,308	3,164	3,044	3,333	3,044	3,226	3,226	3,079	37,588
TOTAL EXPENSE LABOR	15,990	15,990	17,689	15,381	17,689	16,921	16,277	17,826	16,277	17,253	17,253	16,467	201,013
CAPITAL DIRECT RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CAPITAL DIRECT LABOI	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD RECAP													
LABOR	4,333	4,333	4,794	4,169	4,794	4,585	4,411	4,831	4,411	4,675	4,675	4,463	54,474
EMPLOYEE BENEFITS	997	997	1,103	959	1,103	1,055	1,015	1,111	1,015	1,075	1,075	1,026	12,531
TOTAL BU A&G OVERHEAD LAE	5,330	5,330	5,897	5,128	5,897	5,640	5,426	5,942	5,426	5,750	5,750	5,489	67,005
B/S OTHER RECAP													
LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
EMPLOYEE BENEFITS	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL B/S OTHER LABOR	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL LABOR													
LABOR	17,333	17,333	19,175	16,674	19,175	18,342	17,644	19,324	17,644	18,702	18,702	17,851	217,899
EMPLOYEE BENEFITS	3,987	3,987	4,411	3,835	4,411	4,219	4,059	4,444	4,059	4,301	4,301	4,105	50,119
TOTAL	21,320	21,320	23,586	20,509	23,586	22,561	21,703	23,768	21,703	23,003	23,003	21,956	268,018

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LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	132,452	132,561	144,419	127,169	145,041	139,557	133,871	145,940	134,726	141,183	141,183	135,916	1,654,018
EMPLOYEE BENEFITS	30,464	30,489	33,217	29,249	33,359	32,097	30,791	33,566	30,987	32,472	32,472	31,259	380,422
TOTAL EXPENSE LABOR	162,916	163,050	177,636	156,418	178,400	171,654	164,662	179,506	165,713	173,655	173,655	167,175	2,034,440
CAPITAL DIRECT RECAP													
LABOR	28,456	28,466	31,267	27,324	31,451	30,115	28,754	31,494	28,933	30,556	30,556	29,196	356,568
EMPLOYEE BENEFITS	6,544	6,547	7,191	6,285	7,234	6,927	6,613	7,244	6,655	7,028	7,028	6,715	82,011
TOTAL CAPITAL DIRECT LABOR	35,000	35,013	38,458	33,609	38,685	37,042	35,367	38,738	35,588	37,584	37,584	35,911	438,579
BU A&G OVERHEAD RECAP													
LABOR	16,262	16,262	17,893	15,567	17,913	17,346	16,674	18,272	16,748	17,636	17,636	16,835	205,044
EMPLOYEE BENEFITS	3,741	3,741	4,115	3,581	4,120	3,990	3,836	4,203	3,853	4,056	4,056	3,872	47,164
TOTAL BU A&G OVERHEAD LABOR	20,003	20,003	22,008	19,148	22,033	21,336	20,510	22,475	20,601	21,692	21,692	20,707	252,208
B/S OTHER RECAP													
LABOR	11,513	11,515	12,712	11,124	12,771	12,236	11,692	12,780	11,746	12,364	12,364	11,823	144,640
EMPLOYEE BENEFITS	2,648	2,648	2,924	2,559	2,937	2,815	2,689	2,940	2,702	2,843	2,843	2,719	33,267
TOTAL B/S OTHER LABOR	14,161	14,163	15,636	13,683	15,708	15,051	14,381	15,720	14,448	15,207	15,207	14,542	177,907
TOTAL LABOR													
LABOR	188,683	188,804	206,291	181,184	207,176	199,254	190,991	208,486	192,153	201,739	201,739	193,770	2,360,270
EMPLOYEE BENEFITS	43,397	43,425	47,447	41,674	47,650	45,829	43,929	47,953	44,197	46,399	46,399	44,565	542,864
TOTAL	232,080	232,229	253,738	222,858	254,826	245,083	234,920	256,439	236,350	248,138	248,138	238,335	2,903,134

WDVO- Labor Recap

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Schedule 2A

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LABOR RECAP	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	99,006	99,044	108,194	94,938	108,403	104,310	100,286	109,426	100,812	105,693	105,942	101,690	1,237,744
EMPLOYEE BENEFITS	22,772	22,781	24,885	21,836	24,933	23,991	23,066	25,168	23,187	24,310	24,367	23,388	284,684
TOTAL EXPENSE LABOR	121,778	121,825	133,079	116,774	133,336	128,301	123,352	134,594	123,999	130,003	130,309	125,078	1,522,428
CAPITAL DIRECT RECAP													
LABOR	20,331	20,377	22,403	19,524	22,456	21,535	20,663	22,668	20,756	21,810	21,933	21,040	255,496
EMPLOYEE BENEFITS	4,676	4,686	5,152	4,491	5,165	4,953	4,753	5,214	4,774	5,016	5,044	4,839	58,768
TOTAL CAPITAL DIRECT LABOR	25,007	25,063	27,555	24,015	27,621	26,488	25,416	27,882	25,530	26,826	26,977	25,879	314,259
BU A&G OVERHEAD RECAP													
LABOR	13,175	13,175	14,492	12,600	14,502	13,955	13,451	14,734	13,451	14,105	14,105	13,462	165,207
EMPLOYEE BENEFITS	3,030	3,030	3,333	2,898	3,336	3,211	3,093	3,390	3,093	3,245	3,245	3,096	38,000
TOTAL BU A&G OVERHEAD LABOR	16,205	16,205	17,825	15,498	17,838	17,166	16,544	18,124	16,544	17,350	17,350	16,558	203,207
B/S OTHER RECAP													
LABOR	4,861	4,870	5,346	4,649	5,356	5,128	4,904	5,379	4,910	5,151	5,170	4,940	60,664
EMPLOYEE BENEFITS	1,118	1,120	1,230	1,069	1,232	1,180	1,128	1,237	1,130	1,185	1,189	1,136	13,954
TOTAL B/S OTHER LABOR	5,979	5,990	6,576	5,718	6,588	6,308	6,032	6,616	6,040	6,336	6,359	6,076	74,618
TOTAL LABOR													
LABOR	137,373	137,466	150,435	131,711	150,717	144,928	139,304	152,207	139,929	146,759	147,150	141,132	1,719,111
EMPLOYEE BENEFITS	31,596	31,617	34,600	30,294	34,666	33,335	32,040	35,009	32,184	33,756	33,845	32,459	395,401
TOTAL	168,969	169,083	185,035	162,005	185,383	178,263	171,344	187,216	172,113	180,515	180,995	173,591	2,114,512

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Schedule 2A

LABOR RECAP

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EXPENSE RECAP													
LABOR	658,806	658,458	717,000	629,760	719,055	692,424	666,280	726,868	667,679	707,706	703,634	677,886	8,225,556
EMPLOYEE BENEFITS	151,525	151,447	164,913	144,847	165,383	159,257	153,243	167,179	153,565	162,773	161,837	155,910	1,891,879
TOTAL EXPENSE LABOR	810,331	809,905	881,913	774,607	884,438	851,681	819,523	894,047	821,244	870,479	865,471	833,796	10,117,435
CAPITAL DIRECT RECAP													
LABOR	115,750	115,794	127,027	110,936	127,593	122,497	117,172	128,546	117,729	123,905	124,250	118,948	1,450,147
EMPLOYEE BENEFITS	26,622	26,632	29,214	25,516	29,347	28,175	26,950	29,567	27,079	28,498	28,578	27,358	333,536
TOTAL CAPITAL DIRECT LABOR	142,372	142,426	156,241	136,452	156,940	150,672	144,122	158,113	144,808	152,403	152,828	146,306	1,783,683
BU A&G OVERHEAD RECAP													
LABOR	131,682	131,743	144,914	126,123	145,498	139,883	134,067	147,058	134,333	141,497	141,613	135,419	1,653,830
EMPLOYEE BENEFITS	30,289	30,303	33,331	29,011	33,466	32,175	30,837	33,826	30,899	32,545	32,572	31,146	380,400
TOTAL BU A&G OVERHEAD LABOR	161,971	162,046	178,245	155,134	178,964	172,058	164,904	180,884	165,232	174,042	174,185	166,565	2,034,230
B/S OTHER RECAP													
LABOR	36,618	36,744	40,367	35,196	40,489	38,886	37,143	40,705	37,248	39,141	39,194	37,463	459,194
EMPLOYEE BENEFITS	8,422	8,450	9,285	8,095	9,312	8,945	8,543	9,363	8,569	9,001	9,013	8,616	105,614
TOTAL B/S OTHER LABOR	45,040	45,194	49,652	43,291	49,801	47,831	45,686	50,068	45,817	48,142	48,207	46,079	564,808
TOTAL LABOR													
LABOR	942,856	942,739	1,029,308	902,015	1,032,635	993,690	954,662	1,043,177	956,989	1,012,249	1,008,691	969,716	11,788,727
EMPLOYEE BENEFITS	216,858	216,832	236,743	207,469	237,508	228,552	219,573	239,935	220,112	232,817	232,000	223,030	2,711,429
TOTAL	1,159,714	1,159,571	1,266,051	1,109,484	1,270,143	1,222,242	1,174,235	1,283,112	1,177,101	1,245,066	1,240,691	1,192,746	14,500,156

Sample
Schedule 2B

PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
OVERTIME LABOR														
MONTHLY AMOUNT		3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	37,296
TOTAL PAYROLL		3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	3,108	37,296
CAPITAL DIRECT	5%	155	155	155	155	155	155	155	155	155	155	155	155	1,860
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	155	155	155	155	155	155	155	155	155	155	155	155	1,860
EXPENSE PAYROLL		2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	2,798	33,576
STANDBY TIME														
MONTHLY AMOUNT		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
TOTAL PAYROLL		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	3,456	41,472
EMPLOYEE A														
BASE PAY PER HOUR	26.43	4,440	4,440	4,863	4,229	4,863	4,652	4,440	4,863	4,440	4,652	4,652	4,440	54,974
MONTH OF INCREASE	7	0	0	0	0	0	0	178	195	178	186	186	178	1,101
TOTAL PAYROLL		4,440	4,440	4,863	4,229	4,863	4,652	4,618	5,058	4,618	4,838	4,838	4,618	56,075
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	35%	1,554	1,554	1,702	1,480	1,702	1,628	1,616	1,770	1,616	1,693	1,693	1,616	19,624
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,886	2,886	3,161	2,749	3,161	3,024	3,002	3,288	3,002	3,145	3,145	3,002	36,451
EMPLOYEE B														
BASE PAY PER HOUR	14.99	2,518	2,518	2,758	2,398	2,758	2,638	2,518	2,758	2,518	2,638	2,638	2,518	31,179
MONTH OF INCREASE	4	0	0	0	96	110	106	101	110	101	106	106	101	937
TOTAL PAYROLL		2,518	2,518	2,758	2,494	2,868	2,744	2,619	2,868	2,619	2,744	2,744	2,619	32,116
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	252	252	276	249	287	274	262	287	262	274	274	262	3,211
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,266	2,266	2,482	2,245	2,581	2,470	2,357	2,581	2,357	2,470	2,470	2,357	28,905

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PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EMPLOYEE C														
BASE PAY PER HOUR	12.08	2,029	2,029	2,223	1,933	2,223	2,126	2,029	2,223	2,029	2,126	2,126	2,029	25,126
MONTH OF INCREASE	5	0	0	0	0	89	85	81	89	81	85	85	81	676
TOTAL PAYROLL		2,029	2,029	2,223	1,933	2,312	2,211	2,110	2,312	2,110	2,211	2,211	2,110	25,802
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	203	203	222	193	231	221	211	231	211	221	221	211	2,579
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,826	1,826	2,001	1,740	2,081	1,990	1,899	2,081	1,899	1,990	1,990	1,899	23,223
EMPOYEE D														
BASE PAY PER HOUR	11.52	1,935	1,935	2,120	1,843	2,120	2,028	1,935	2,120	1,935	2,028	2,028	1,935	23,962
MONTH OF INCREASE	10	0	0	0	0	0	0	0	0	0	81	81	77	239
TOTAL PAYROLL		1,935	1,935	2,120	1,843	2,120	2,028	1,935	2,120	1,935	2,109	2,109	2,012	24,201
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	10%	194	194	212	184	212	203	194	212	194	211	211	201	2,422
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,741	1,741	1,908	1,659	1,908	1,825	1,741	1,908	1,741	1,898	1,898	1,811	21,779
EMPLOYEE E														
BASE PAY PER HOUR	20.76	3,488	3,488	3,820	3,322	3,820	3,654	3,488	3,820	3,488	3,654	3,654	3,488	43,181
MONTH OF INCREASE	8	0	0	0	0	0	0	0	153	140	146	146	140	725
TOTAL PAYROLL		3,488	3,488	3,820	3,322	3,820	3,654	3,488	3,973	3,628	3,800	3,800	3,628	43,906
CAPITAL DIRECT	15%	523	523	573	498	573	548	523	596	544	570	570	544	6,585
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,965	2,965	3,247	2,824	3,247	3,106	2,965	3,377	3,084	3,230	3,230	3,084	37,321
EMPLOYEE F														
BASE PAY PER HOUR	19.03	3,197	3,197	3,502	3,045	3,502	3,349	3,197	3,502	3,197	3,349	3,349	3,197	39,582
MONTH OF INCREASE	1	128	128	140	122	140	134	128	140	128	134	134	128	1,584
TOTAL PAYROLL		3,325	3,325	3,642	3,167	3,642	3,483	3,325	3,642	3,325	3,483	3,483	3,325	41,166
CAPITAL DIRECT	10%	333	333	364	317	364	348	333	364	333	348	348	333	4,118
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,992	2,992	3,278	2,850	3,278	3,135	2,992	3,278	2,992	3,135	3,135	2,992	37,048

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE.		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
EMPLOYEE G														
BASE PAY PER HOUR	15.37	2,582	2,582	2,828	2,459	2,828	2,705	2,582	2,828	2,582	2,705	2,705	2,582	31,970
MONTH OF INCREASE	1	103	103	113	98	113	108	103	113	103	108	108	103	1,276
TOTAL PAYROLL		2,685	2,685	2,941	2,557	2,941	2,813	2,685	2,941	2,685	2,813	2,813	2,685	33,246
CAPITAL DIRECT	65%	1,745	1,745	1,912	1,662	1,912	1,829	1,745	1,912	1,745	1,829	1,829	1,745	21,610
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	537	537	588	511	588	563	537	588	537	563	563	537	6,649
EXPENSE PAYROLL		403	403	441	384	441	421	403	441	403	421	421	403	4,987
EMPLOYEE H														
BASE PAY PER HOUR	17.66	2,967	2,967	3,249	2,826	3,249	3,108	2,967	3,249	2,967	3,108	3,108	2,967	36,733
MONTH OF INCREASE	1	119	119	130	113	130	124	119	130	119	124	124	119	1,470
TOTAL PAYROLL		3,086	3,086	3,379	2,939	3,379	3,232	3,086	3,379	3,086	3,232	3,232	3,086	38,203
CAPITAL DIRECT	5%	154	154	169	147	169	162	154	169	154	162	162	154	1,910
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	154	154	169	147	169	162	154	169	154	162	162	154	1,910
EXPENSE PAYROLL		2,778	2,778	3,041	2,645	3,041	2,908	2,778	3,041	2,778	2,908	2,908	2,778	34,383
EMPLOYEE I														
BASE PAY PER HOUR	18.12	3,044	3,044	3,334	2,899	3,334	3,189	3,044	3,334	3,044	3,189	3,189	3,044	37,690
MONTH OF INCREASE	10	0	0	0	0	0	0	0	0	0	128	128	122	378
TOTAL PAYROLL		3,044	3,044	3,334	2,899	3,334	3,189	3,044	3,334	3,044	3,317	3,317	3,166	38,068
CAPITAL DIRECT	65%	1,979	1,979	2,167	1,884	2,167	2,073	1,979	2,167	1,979	2,156	2,156	2,058	24,744
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	609	609	667	580	667	638	609	667	609	663	663	633	7,614
EXPENSE PAYROLL		456	456	500	435	500	478	456	500	456	498	498	475	5,710
EMPLOYEE J														
BASE PAY PER HOUR	19.98	3,357	3,357	3,676	3,197	3,676	3,516	3,357	3,676	3,357	3,516	3,516	3,357	41,558
MONTH OF INCREASE	1	134	134	147	128	147	141	134	147	134	141	141	134	1,662
TOTAL PAYROLL		3,491	3,491	3,823	3,325	3,823	3,657	3,491	3,823	3,491	3,657	3,657	3,491	43,220
CAPITAL DIRECT	65%	2,269	2,269	2,485	2,161	2,485	2,377	2,269	2,485	2,269	2,377	2,377	2,269	28,092
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	698	698	765	665	765	731	698	765	698	731	731	698	8,643
EXPENSE PAYROLL		524	524	573	499	573	549	524	573	524	549	549	524	6,485

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PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	23	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EMPLOYEE K														
BASE PAY PER HOUR	15.74	2,644	2,644	2,896	2,518	2,896	2,770	2,644	2,896	2,644	2,770	2,770	2,644	32,739
MONTH OF INCREASE	10	0	0	0	0	0	0	0	0	0	111	111	106	328
TOTAL PAYROLL		2,644	2,644	2,896	2,518	2,896	2,770	2,644	2,896	2,644	2,881	2,881	2,750	33,067
CAPITAL DIRECT	65%	1,719	1,719	1,883	1,637	1,883	1,801	1,719	1,883	1,719	1,873	1,873	1,788	21,497
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	529	529	579	504	579	554	529	579	529	576	576	550	6,613
EXPENSE PAYROLL		396	396	434	377	434	415	396	434	396	432	432	412	4,957
EMPLOYEE L														
BASE PAY PER HOUR	17.98	3,021	3,021	3,308	2,877	3,308	3,164	3,021	3,308	3,021	3,164	3,164	3,021	37,398
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	121	127	127	121	496
TOTAL PAYROLL		3,021	3,021	3,308	2,877	3,308	3,164	3,021	3,308	3,142	3,291	3,291	3,142	37,894
CAPITAL DIRECT	65%	1,963	1,963	2,150	1,870	2,150	2,057	1,963	2,150	2,042	2,139	2,139	2,042	24,628
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	604	604	662	575	662	633	604	662	628	658	658	628	7,578
EXPENSE PAYROLL		454	454	496	432	496	474	454	496	472	494	494	472	5,688
EMPLOYEE M														
BASE PAY PER HOUR	14.07	2,364	2,364	2,589	2,251	2,589	2,476	2,364	2,589	2,364	2,476	2,476	2,364	29,266
MONTH OF INCREASE	1	95	95	104	90	104	99	95	104	95	99	99	95	1,174
TOTAL PAYROLL		2,459	2,459	2,693	2,341	2,693	2,575	2,459	2,693	2,459	2,576	2,575	2,459	30,440
CAPITAL DIRECT	65%	1,598	1,598	1,750	1,522	1,750	1,674	1,598	1,750	1,598	1,674	1,674	1,598	19,784
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	492	492	539	468	539	515	492	539	492	515	515	492	6,090
EXPENSE PAYROLL		369	369	404	351	404	386	369	404	369	386	386	369	4,566
EMPLOYEE N														
BASE PAY PER HOUR	12.85	2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,159	2,262	2,262	2,159	26,728
MONTH OF INCREASE	3	0	0	95	82	95	90	86	95	86	90	90	86	895
TOTAL PAYROLL		2,159	2,159	2,459	2,138	2,459	2,352	2,245	2,459	2,245	2,352	2,352	2,245	27,623
CAPITAL DIRECT	45%	971	971	1,107	962	1,107	1,058	1,010	1,107	1,010	1,058	1,058	1,010	12,429
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	10%	216	216	246	214	246	235	224	246	224	235	235	224	2,761
EXPENSE PAYROLL		972	972	1,106	962	1,106	1,059	1,011	1,106	1,011	1,059	1,059	1,011	12,433

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PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EMPLOYEE O														
BASE PAY PER HOUR	18.07	3,036	3,036	3,325	2,891	3,325	3,180	3,036	3,325	3,036	3,180	3,180	3,036	37,586
MONTH OF INCREASE	2	0	121	133	116	133	127	121	133	121	127	127	121	1,380
TOTAL PAYROLL		3,036	3,157	3,458	3,007	3,458	3,307	3,157	3,458	3,157	3,307	3,307	3,157	38,966
CAPITAL DIRECT	8%	243	253	277	241	277	265	253	277	253	265	265	253	3,122
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	61	63	69	60	69	66	63	69	63	66	66	63	778
EXPENSE PAYROLL		2,732	2,841	3,112	2,706	3,112	2,976	2,841	3,112	2,841	2,976	2,976	2,841	35,066
EMPLOYEE P														
BASE PAY PER HOUR	17.89	3,006	3,006	3,292	2,862	3,292	3,149	3,006	3,292	3,006	3,149	3,149	3,006	37,211
MONTH OF INCREASE	1	120	120	132	114	132	126	120	132	120	126	126	120	1,488
TOTAL PAYROLL		3,126	3,126	3,424	2,976	3,424	3,275	3,126	3,424	3,126	3,275	3,275	3,126	38,699
CAPITAL DIRECT	8%	250	250	274	238	274	262	250	274	250	262	262	250	3,096
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	63	63	68	60	68	65	63	68	63	65	65	63	774
EXPENSE PAYROLL		2,813	2,813	3,082	2,678	3,082	2,948	2,813	3,082	2,813	2,948	2,948	2,813	34,829
EMPLOYEE Q														
BASE PAY PER HOUR	14.10	2,369	2,369	2,594	2,256	2,594	2,482	2,369	2,594	2,369	2,482	2,482	2,369	29,328
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	95	95
TOTAL PAYROLL		2,369	2,369	2,594	2,256	2,594	2,482	2,369	2,594	2,369	2,482	2,482	2,464	29,423
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,369	2,369	2,594	2,256	2,594	2,482	2,369	2,594	2,369	2,482	2,482	2,464	29,423
EMPLOYEE R														
BASE PAY PER HOUR	16.44	2,762	2,762	3,025	2,630	3,025	2,893	2,762	3,025	2,762	2,893	2,893	2,762	34,195
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	110	110
TOTAL PAYROLL		2,762	2,762	3,025	2,630	3,025	2,893	2,762	3,025	2,762	2,893	2,893	2,872	34,305
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,762	2,762	3,025	2,630	3,025	2,893	2,762	3,025	2,762	2,893	2,893	2,872	34,305

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
EMPLOYEE S														
BASE PAY PER HOUR	16.36	2,748	2,748	3,010	2,618	3,010	2,879	2,748	3,010	2,748	2,879	2,879	2,748	34,029
MONTH OF INCREASE	10	0	0	0	0	0	0	0	0	0	115	115	110	340
TOTAL PAYROLL		2,748	2,748	3,010	2,618	3,010	2,879	2,748	3,010	2,748	2,994	2,994	2,858	34,369
CAPITAL DIRECT	8%	220	220	241	209	241	230	220	241	220	240	240	229	2,751
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	55	55	60	52	60	58	55	60	55	60	60	57	687
EXPENSE PAYROLL		2,473	2,473	2,709	2,357	2,709	2,591	2,473	2,709	2,473	2,694	2,694	2,572	30,931
EMPLOYEE T														
BASE PAY PER HOUR	13.31	2,236	2,236	2,449	2,130	2,449	2,343	2,236	2,449	2,236	2,343	2,343	2,236	27,685
MONTH OF INCREASE	6	0	0	0	0	0	94	89	98	89	94	94	89	647
TOTAL PAYROLL		2,236	2,236	2,449	2,130	2,449	2,437	2,325	2,547	2,325	2,437	2,437	2,325	28,332
CAPITAL DIRECT	8%	179	179	196	170	196	195	186	204	186	195	195	186	2,267
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	45	45	49	43	49	49	47	51	47	49	49	47	570
EXPENSE PAYROLL		2,012	2,012	2,204	1,917	2,204	2,193	2,092	2,292	2,092	2,193	2,193	2,092	25,495
EMPLOYEE U														
BASE PAY PER HOUR	15.91	2,673	2,673	2,927	2,546	2,927	2,800	2,673	2,927	2,673	2,800	2,800	2,673	33,093
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	107	107
TOTAL PAYROLL		2,673	2,673	2,927	2,546	2,927	2,800	2,673	2,927	2,673	2,800	2,800	2,780	33,200
CAPITAL DIRECT	8%	214	214	234	204	234	224	214	234	214	224	224	222	2,656
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	53	53	59	51	59	56	53	59	53	56	56	56	664
EXPENSE PAYROLL		2,406	2,406	2,634	2,291	2,634	2,520	2,406	2,634	2,406	2,520	2,520	2,502	29,880
EMPLOYEE V														
BASE PAY PER HOUR	13.08	2,197	2,197	2,407	2,093	2,407	2,302	2,197	2,407	2,197	2,302	2,302	2,197	27,206
MONTH OF INCREASE	6	0	0	0	0	0	92	88	96	88	92	92	88	636
TOTAL PAYROLL		2,197	2,197	2,407	2,093	2,407	2,394	2,285	2,503	2,285	2,394	2,394	2,285	27,842
CAPITAL DIRECT	8%	176	176	193	167	193	192	183	200	183	192	192	183	2,230
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	44	44	48	42	48	48	46	50	46	48	48	46	558
EXPENSE PAYROLL		1,977	1,977	2,166	1,884	2,166	2,154	2,056	2,253	2,056	2,154	2,154	2,056	25,054

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
EMPLOYEE W														
BASE PAY PER HOUR	15.75	2,646	2,646	2,898	2,520	2,898	2,772	2,646	2,898	2,646	2,772	2,772	2,646	32,760
MONTH OF INCREASE	1	106	106	116	101	116	111	106	116	106	111	111	106	1,312
TOTAL PAYROLL		2,752	2,752	3,014	2,621	3,014	2,883	2,752	3,014	2,752	2,883	2,883	2,752	34,072
CAPITAL DIRECT	8%	220	220	241	210	241	231	220	241	220	231	231	220	2,726
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	55	55	60	52	60	58	55	60	55	58	58	55	681
EXPENSE PAYROLL		2,477	2,477	2,713	2,359	2,713	2,594	2,477	2,713	2,477	2,594	2,594	2,477	30,665
EMPLOYEE X														
BASE PAY PER HOUR	18.96	3,185	3,185	3,489	3,034	3,489	3,337	3,185	3,489	3,185	3,337	3,337	3,185	39,437
MONTH OF INCREASE	1	127	127	140	121	140	133	127	140	127	133	133	127	1,575
TOTAL PAYROLL		3,312	3,312	3,629	3,155	3,629	3,470	3,312	3,629	3,312	3,470	3,470	3,312	41,012
CAPITAL DIRECT	10%	331	331	363	315	363	347	331	363	331	347	347	331	4,100
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	166	166	181	158	181	173	166	181	166	173	173	166	2,050
EXPENSE PAYROLL		2,815	2,815	3,085	2,682	3,085	2,950	2,815	3,085	2,815	2,950	2,950	2,815	34,862
EMPLOYEE Y														
BASE PAY PER HOUR	24.82	4,170	4,170	4,567	3,971	4,567	4,368	4,170	4,567	4,170	4,368	4,368	4,170	51,626
MONTH OF INCREASE	1	167	167	183	159	183	175	167	183	167	175	175	167	2,068
TOTAL PAYROLL		4,337	4,337	4,750	4,130	4,750	4,543	4,337	4,750	4,337	4,543	4,543	4,337	53,694
CAPITAL DIRECT	15%	651	651	712	620	712	681	651	712	651	681	681	651	8,054
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	5%	217	217	237	207	237	227	217	237	217	227	227	217	2,684
EXPENSE PAYROLL		3,469	3,469	3,801	3,303	3,801	3,635	3,469	3,801	3,469	3,635	3,635	3,469	42,956
EMPLOYEE Z														
BASE PAY PER HOUR	15.37	2,582	2,582	2,828	2,459	2,828	2,705	2,582	2,828	2,582	2,705	2,705	2,582	31,970
MONTH OF INCREASE	4	0	0	0	98	113	108	103	113	103	108	108	103	957
TOTAL PAYROLL		2,582	2,582	2,828	2,557	2,941	2,813	2,685	2,941	2,685	2,813	2,813	2,685	32,927
CAPITAL DIRECT	8%	207	207	226	205	235	225	215	235	215	225	225	215	2,635
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	52	52	57	51	59	56	54	59	54	56	56	54	660
EXPENSE PAYROLL		2,323	2,323	2,545	2,301	2,647	2,532	2,416	2,647	2,416	2,532	2,532	2,416	29,632

Schedule 2B

8.7.9

PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
EMPLOYEE AA														
BASE PAY PER HOUR	15.68	2,634	2,634	2,885	2,509	2,885	2,760	2,634	2,885	2,634	2,760	2,760	2,634	32,614
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	105	105
TOTAL PAYROLL		2,634	2,634	2,885	2,509	2,885	2,760	2,634	2,885	2,634	2,760	2,760	2,739	32,719
CAPITAL DIRECT	8%	211	211	231	201	231	221	211	231	211	221	221	219	2,620
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	53	53	58	50	58	55	53	58	53	55	55	55	656
EXPENSE PAYROLL		2,370	2,370	2,596	2,258	2,596	2,484	2,370	2,596	2,370	2,484	2,484	2,465	29,443
EMPLOYEE BB														
BASE PAY PER HOUR	15.83	2,659	2,659	2,913	2,533	2,913	2,786	2,659	2,913	2,659	2,786	2,786	2,659	32,928
MONTH OF INCREASE	12	0	0	0	0	0	0	0	0	0	0	0	106	106
TOTAL PAYROLL		2,659	2,659	2,913	2,533	2,913	2,786	2,659	2,913	2,659	2,786	2,786	2,765	33,032
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,659	2,659	2,913	2,533	2,913	2,786	2,659	2,913	2,659	2,786	2,786	2,765	33,032
EMPLOYEE CC														
BASE PAY PER HOUR	12.85	2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,159	2,262	2,262	2,159	26,728
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	86	90	90	86	352
TOTAL PAYROLL		2,159	2,159	2,364	2,056	2,364	2,262	2,159	2,364	2,245	2,352	2,352	2,245	27,080
CAPITAL DIRECT	65%	1,403	1,403	1,537	1,336	1,537	1,470	1,403	1,537	1,459	1,529	1,529	1,459	17,602
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	20%	432	432	473	411	473	452	432	473	449	470	470	449	5,416
EXPENSE PAYROLL		324	324	354	309	354	340	324	354	337	353	353	337	4,062
EMPLOYEE DD														
BASE PAY PER HOUR	16.53	2,777	2,777	3,042	2,645	3,042	2,909	2,777	3,042	2,777	2,909	2,909	2,777	34,382
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	111	116	116	111	454
TOTAL PAYROLL		2,777	2,777	3,042	2,645	3,042	2,909	2,777	3,042	2,888	3,025	3,025	2,888	34,836
CAPITAL DIRECT	8%	222	222	243	212	243	233	222	243	231	242	242	231	2,786
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	2%	56	56	61	53	61	58	56	61	58	61	61	58	700
EXPENSE PAYROLL		2,499	2,499	2,738	2,380	2,738	2,618	2,499	2,738	2,599	2,722	2,722	2,599	31,350

Schedule 2B

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		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
PAYROLL INCREASE RATE		4.00%												
BENEFITS RATE		23.00%												
NUMBER OF WORK DAYS		21	21	23	20	23	22	21	23	21	22	22	21	260
		1	2	3	4	5	6	7	8	9	10	11	12	
NUMBER OF WORK HOURS		168	168	184	160	184	176	168	184	168	176	176	168	2,080
EMPLOYEE EE														
BASE PAY PER HOUR	26.91	4,521	4,521	4,951	4,306	4,951	4,736	4,521	4,951	4,521	4,736	4,736	4,521	56,973
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	181	189	189	181	740
TOTAL PAYROLL		4,521	4,521	4,951	4,306	4,951	4,736	4,521	4,951	4,702	4,925	4,925	4,702	56,713
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	35%	1,582	1,582	1,733	1,507	1,733	1,658	1,582	1,733	1,646	1,724	1,724	1,646	19,850
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		2,939	2,939	3,218	2,799	3,218	3,078	2,939	3,218	3,056	3,201	3,201	3,056	36,863
EMPLOYEE FF														
BASE PAY PER HOUR	9.38	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,576	1,651	1,651	1,576	19,510
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	63	66	66	63	258
TOTAL PAYROLL		1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	1,717	1,717	1,639	19,768
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	1,717	1,717	1,639	19,768
EMPLOYEE GG														
BASE PAY PER HOUR	9.38	1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,576	1,651	1,651	1,576	19,510
MONTH OF INCREASE	9	0	0	0	0	0	0	0	0	63	66	66	63	258
TOTAL PAYROLL		1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	1,717	1,717	1,639	19,768
CAPITAL DIRECT	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
BU A&G OVERHEAD	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
B/S OTHER	0%	0	0	0	0	0	0	0	0	0	0	0	0	0
EXPENSE PAYROLL		1,576	1,576	1,726	1,501	1,726	1,651	1,576	1,726	1,639	1,717	1,717	1,639	19,768

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #2 Dated September 20, 1999
DR Item 51
Witness: Betty Adams

Data Request:

Refer to the response to the AG's August 19, 1999 Data Request, Item 165. Explain the amortized merger and acquisition costs and expenses applicable to Western.

Response:

See response to Attorney General request dated September 20, 1999, DR Item 8, part a.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #2 Dated September 20, 1999
DR Item 52
Witness: Betty Adams

Data Request:

Refer to the response to the AG's August 19, 1999 Data Request, Item 179. Explain how the $4,536 total medical costs per employee per year in part (c) is determined, i.e., $X for medical per month, $Y for dental per month, and any distinction between single employee costs versus married employee costs.

Response:

The breakdown is $4,128 (91%) for medical costs and $408 (9%) for dental costs per employee per year. This is the average cost regardless of the coverage elected by the employee - single or married.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 53
Witness: Betty L. Adams

Data Request:

Refer to the response to the AG's August 19, 1999 Data Request, Item 216. Are there any indirect lobbying activity expenses allocated to Western from Atmos or Shared Services in the forecasted test year? Explain the response in detail.

Response:

Following the response to AG's August 19, 1999 Data Request, Item 216, there are no indirect lobbying expenses included in the cost of service. All Atmos or Shared Services lobbying expenses are recorded in account 4261, which is not included in our cost or service.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 54
Witness: Betty L. Adams

Data Request:

Are there any non-recurring expenditures included in operating and maintenance expenses for the base period or forecasted test year? Explain and describe the nature and amounts of these non-recurring expenditures.

Response:

The only non-recurring expense for the base year is $400,000 for the Demand Side Management (DSM) pilot program, WKG Cares as stated in my testimony. The base year, plus the first 3 months of FY 2000 (which is not in our forecasted year) completes our pilot program. There are no non-recurring expenses in our forecasted test year.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 55
Witness: Betty L. Adams

Data Request:

Refer to the response to Item 61(b) of the Commission's August 19, 1999 Order. If FR 10(10)(c)2, at Volume 10 of 10 of the Application, Tab 3 of the Application address the amounts of functional expense for directors retirement benefits, community trade relations and trade shows, and sports activities, specify the amounts and explain or describe the nature of the expenditures. Western's response to the Commission's August 19, 1999 Order appears to be non-responsive to these items of expense. If the above-mentioned expenses are not addressed in FR 10(10)(c)2, resubmit the response to Item 61(b).

Response:

There is $59,965 of director retirement benefits included in the base period and $0 in the forecasted period. These expenses are to fund a retirement plan for the members of the Board of Directors for the Corporation. As indicated in KPSC 3-56, Atmos is not the parent company of WKG. WKG is an operating division of Atmos and is not a separate corporate entity, therefore, this Board is Western's Board of Directors. The cost of funding a retirement plan for this Board is essential for Atmos to attract and maintain directors which bring professionalism, expertise and experience to the Board. This skilled Board in turn, provides strong leadership and oversight which ensures ratepayers receive the highest quality service at the lowest cost.

There is $20,000 for community trade relations and trade shows included in the base period and $15,000 for the forecasted period. These expenditures allow WKG to participate in and/or sponsor selected trade shows in cooperation with area home builders, professional associations, industrial foundations and Chambers of Commerce. Please refer to KPSC 3-49 for a listing of these organizations with an explanation of why they should be included for rate making purposes.

Costs related to sports activities are included in Schedule F.2.3, Volume 10 of 10, Tab 6, on line 2, Employee Activities. These costs have been excluded for rate making in an adjustment found in FR 10(10)(c)2, Volume 10 of 10, Tab 3, Line 12.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 56
Witness: Betty Adams

Data Request:

As stated in 22(b), the schedule of Shared Services "Combined Direct & Billed" total monthly expenses as allocated by division on the exhibit in response to DR Item 83a, "April's Financial Statements," bottom of the page marked "(33), (34) and (35)" appear to represent a detailed statement of operating expenses. Additionally, this statement allocates total Shared Services costs to the divisions to which Shared Services costs apply.

a. Explain whether any Shared Services costs are allocable to Atmos as parent company expenses.

b. Describe how applicable costs are allocated to Atmos as parent company expenses.

c. Are any of the Shared Services costs and expenses allocated to the gas operating divisions of Atmos "below the line" expenses according to FERC, i.e. investor relations, new business ventures, and directors retirement? Explain the response in detail.

Response:

Atmos is not the parent company of WKG. WKG is an operating division of Atmos and is not a separate corporate entity. Atmos conducts business in Kentucky under the name Western Kentucky Gas Company pursuant to a certificate filed with the Kentucky Secretary of States Office.

a. There are no Shared Services costs which are allocable to Atmos as parent company expenses. All Shared Services costs are allocated to all Atmos' utility divisions, because of the organization structure described above.

b. See part a above.

c. Atmos treats such costs as investor relations, new business ventures and directors retirement as operations and maintenance expenses classified as NARUC account 930. These costs are believed to be beneficial to the gas operating divisions in that it allows them to realize the benefits of being part of a larger, more efficient organization. All of these functions would be performed by each operating division if it were not part of the Atmos corporation and were instead a separate entity.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 57

Data Request:

Refer to the filing requirements at Volume 10 of 10 of the Application, Tab 3, Exhibit FR 10(10)(c), Schedule C-2.

a. If Western's application did not employ a forecasted test year, but employed the historical test year ended September 30, 1998, normalized to reflect known and measurable adjustments, would the type of adjustments termed "utility budget adjustments, SSU billing adjustments, and rate making adjustments" on Schedule C-2 be the same? Provide a detailed explanation.

b. What would the dollar amounts of the adjustments be from the standpoint of normalizing known and measurable adjustments?

Response:

The KPSC has amended this question and set a new response date of October 8, 1999.

Western Kentucky Gas Company
Case No. 99-070
KPSC Data Request #3 Dated September 20, 1999
DR Item 58
Witness: Buchanan

Data Request:

Concerning the capital budget projects included in the estimated portion of the base period and the forecasted period, Western has assumed the actual expenditures on these projects will be equal to the budgeted amounts. Based on the nine fiscal years of information provided by Western concerning its capital budget projects' completion percentage, Western's historic completion percentage is 94 percent.[1]

a. Restate all capital project budget amounts shown on Exhibit DHD-1 for the estimated months of the base period and for the entire forecasted period, reflecting the historic 94 percent completion factor.

b. Recalculate Western's base period rate base, balance sheet, and operating income statement reflecting the impact of applying the 94 percent completion factor. Include all workpapers, assumptions, and calculations used to determine the recalculated amounts. Provide this information on diskette using Excel spreadsheets as was done in responses to previous data requests.

c. Recalculate Western's forecasted revenue requirement, rate base, balance sheet, and operating income statement reflecting the impact of applying the 94 percent completion factor. Include all workpapers, assumptions, and calculations used to determine the recalculated amounts. Provide this information on diskette using Excel spreadsheets as was done in responses to previous data requests.

d. Western has also identified corrections and revisions to other financial information, which it has submitted in conjunction with its responses to various data requests. An example of such a revision is contained in the response to the AG's Initial Data Request, Volume 3 of 3, Item 206. When preparing the recalculation of the information required in parts (b) and (c) above, recognize and incorporate the impact of all corrections and revisions submitted by Western since the filing of its application.Include in the workpapers, assumptions, and calculations the appropriate cross-references to the location in the record of these corrections and revisions.

Response:

Additional time is required to develop the requested information. Western expects this will take one week.

[1] Total capital project expenditures for the nine fiscal years equals $101,474,634; total capital project budgets for the same nine fiscal years equals $107,992,213. Dividing the expenditures by the budget equals 94 percent.